Appendix A: Seismic Survey Mitigation and Protected Species Observer Protocols

These protocols will be implemented by the Bureau of Ocean Energy Management (BOEM), the Bureau of Safety and Environmental Enforcement (BSEE), and provide guidelines to operators in complying with the Endangered Species Act (ESA; 16 U.S.C. §§ 1531-1544) and Marine Mammal Protection Act (MMPA; 16 U.S.C. §§1361- 1423h). The measures contained herein apply to all seismic surveys approved by BOEM and associated with the federally regulated oil and gas program in the Gulf of Mexico.

Background

Geophysical surveys, including the use of airguns and airgun arrays,may have an impact on marine wildlife. Many marine species are protected under the Endangered Species Act (ESA) and all marine mammals (including manatees) are protected under the Marine Mammal Protection Act (MMPA). The following Gulf of Mexico species are listed under the ESA:

ESA-listed Species common to the Gulf of Mexico
Gulf of Mexico Bryde's Whale (*Balaenoptera edeni*)
Sperm Whale (*Physeter macrocephalus*)
Green Turtle (*Chelonia mydas*) – North Atlantic DPS and South Atlantic DPS
Hawksbill Turtle (*Eretmochelys imbricata)*
Kemp's Ridley Turtle (*Lepidochelys kempii*)
Leatherback Turtle (*Dermochelys coriacea*) - Northwest Atlantic DPS
Loggerhead Turtle (*Caretta caretta*) – Northwest Atlantic Ocean DPS
Gulf Sturgeon (*Acipenser oxyrinchus desotoi*)
Oceanic Whitetip Shark (*Carcharhinus longimanus*)
Giant Manta Ray (*Manta birostris*)
West Indian Manatee (*Trichechus manatus*)*

**Managed by the US Fish and Wildlife Service*

Note that this list can change as other species are listed/delisted, and this protocol shall be applied to any ESA protected species (and all marine mammals) that occur in the Gulf of Mexico, including rare and extralimital species.

BSEE and BOEM consult jointly with the National Marine Fisheries Service (NMFS) and the U.S. Fish and Wildlife Service (FWS) under Section 7 of the ESA to ensure that BOEM- or BSEE-authorized activities do not jeopardize the continued existence of ESA-listed species nor result in destruction or adverse modification of designated critical habitat. Incidental take of ESA-listed species is prohibited except as authorized pursuant to an Incidental Take Statement in the attached Biological Opinion. Incidental take of ESA-listed marine mammals cannot be exempted under the ESA unless also authorized under the MMPA. In this case, NMFS is

developing an incidental take regulation (ITR) to facilitate subsequent issuance of MMPA authorization (as applicable) to operators to authorize take incidental to seismic surveys. The proposed regulations would establish a framework for authorization of incidental take by Level A and Level B harassment through MMPA authorization (as applicable). Once an ITR and subsequent LOA is complete, the Biological Opinion and associated Incidental Take Statement may be amended to exempt take for Gulf of Mexico Bryde's whale and sperm whale, which are listed under the ESA. Following development of the ITRs, implementation could occur via issuance of MMPA authorization (as applicable and as Letters of Authorization [LOAs]) upon request from individual industry applicants planning specific seismic survey activities.

These protocols are the result of coordination between BOEM, BSEE, and NMFS and are based on: past and present mitigation measures; terms and conditions and reasonable and prudent measures identified in the attached Biological Opinion issued to the Bureaus; conditions, mitigation, monitoring, and reporting requirements identified in the MMPA ITR; and NMFS' technical memorandum on standards for a protected species observer and data management program (Baker et al. 2013). BSEE is tasked as the lead agency for compiling lessee or operator reporting data required under current Biological Opinions applicable to both Bureaus. Therefore, while BOEM is issuing these protocols, all observer reports described herein must be submitted to BSEE as well as to NMFS where specified.

In order to protect ESA-listed species and marine mammals during seismic operations, seismic operators will be required to use protected species observers (PSOs) and follow specific seismic survey protocols when operating. These measures contained herein apply to all on-lease ancillary activity surveys conducted under 30 CFR Part 550 and all off-lease surveys conducted under 30 CFR Part 551, regardless of water depth. Operators must demonstrate your compliance with these requirements by submitting to BSEE and NMFS certain reports as detailed below.

Definitions

Terms used in these protocols have the following meanings:

1. Protected species means any species listed under the ESA and/or protected by the MMPA. The requirements discussed herein focus on marine mammals and sea turtles since these species are the most likely to be observed during seismic surveys. However, other ESA-listed species (e.g., giant manta rays) are also protected and observations of them should be reported as detailed below.
2. Airgun means a device that releases compressed air into the water column, creating an acoustical energy pulse with the purpose of penetrating the seafloor.
3. Deep penetration surveys are those using a large airgun array as the acoustic source. These surveys may in some cases collect return signals using sensors incorporated into ocean-bottom cables (OBC) or autonomous ocean-bottom nodes (OBN) placed

on the seafloor. These surveys are also referred to as high energy surveys.

4. Shallow penetration surveys are those using a small airgun array or single airgun, or could include certain non-airgun acoustic sources (e.g., “boomer,” a type of sub-bottom profiler) as the acoustic source. These surveys are also referred to as low energy surveys.
5. Ramp-up (sometimes referred to as "soft start") means the gradual and systematic increase of emitted sound levels from an airgun array. Ramp-up begins by first activating a single airgun of the smallest volume, followed by doubling the number of active elements in stages until the full complement of an array's airguns are active. Each stage should be approximately the same duration, and the total duration should not be less than approximately 20 minutes for deep penetration surveys.
6. Shutdown of an airgun array means the immediate de-activation of all individual airgun elements of the array.
7. Exclusion zone means the area to be monitored for possible shutdown in order to reduce or eliminate the potential for injury of protected species. Two exclusion zones are defined, depending on the species and context. For beaked whales, *Kogia* spp., sperm whales, and baleen whales, the exclusion zone encompasses the area at and below the sea surface out to a radius of 1.5 kilometers from the edges of the airgun array (0–1,500 meters). For all other protected species, the exclusion zone encompasses the area at and below the sea surface out to a radius of 500 meters from the edges of the airgun array (0–500 meters).
8. Buffer zone means an area beyond the exclusion zone to be monitored for the presence of protected species that may enter the exclusion zone. During pre-clearance monitoring (i.e., before ramp-up begins), the buffer zone also acts as an extension of the exclusion zone in that observations of marine mammals and sea turtles within the buffer zone would also prevent airgun operations from beginning (i.e. ramp-up). The buffer zone is not applicable for contexts that require an exclusion zone beyond 500 meters. The buffer zone encompasses the area at and below the sea surface from the edge of the 0– 500 meter exclusion zone, out to a radius of 1000 meters from the edges of the airgun array (500–1,000 meters).
9. Visual monitoring means the use of trained protected species observers (herein referred to as visual PSOs) to scan the ocean surface visually for the presence of protected species. These observers must have successfully completed a visual observer training program as described below. The area to be scanned visually includes primarily the exclusion zone, but also the buffer zone. Visual monitoring of the exclusion zones and adjacent waters is intended to establish and, when visual conditions allow, maintain zones around the sound source that are clear of marine mammals and sea turtles, thereby reducing or eliminating the potential for injury. Visual monitoring of the buffer zone is intended to (1) provide additional protection to marine mammals and sea turtles and awareness and potential protection of other visual protected species that may be in

the area during pre-clearance, and (2) during airgun use, aid in establishing and maintaining the exclusion zone by alerting the visual observer and crew of marine mammals and sea turtles that are outside of, but may approach and enter, the exclusion zone.

10. Acoustic monitoring means the use of trained personnel (sometimes referred to as passive acoustic monitoring [PAM] operators, herein referred to as acoustic PSOs) to operate PAM equipment to acoustically detect the presence of marine mammals. These observers must have successfully completed a passive acoustic observer training program as described below. Acoustic monitoring is intended to further support visual monitoring in maintaining an exclusion zone around the sound source that is clear of marine mammals, in part for the purpose of reducing or eliminating the potential for injury. In cases where visual monitoring is not effective (e.g., due to weather, nighttime), acoustic monitoring may be used to allow certain activities to occur, as further detailed below.

General Requirements

1. A copy of a MMPA incidental take authorization (as applicable) and BOEM-approved Permit/Plan must be in the possession of the vessel operator, other relevant personnel, the lead PSO (see description below), and any other relevant designees operating under the authority of the MMPA authorization (as applicable) and BOEM Permit/Plan.
2. The MMPA authorization (as applicable) and BOEM-approved Permit/Plan holder shall instruct relevant vessel personnel with regard to the authority of the protected species monitoring team, and shall ensure that relevant vessel personnel and the protected species monitoring team participate in a joint onboard briefing (hereafter PSO briefing) led by the vessel operator and lead PSO to ensure that responsibilities, communication procedures, protected species monitoring protocols, operational procedures, and MMPA authorization (as applicable) and BOEM Permit/Plan requirements are clearly understood. This PSO briefing must be repeated when relevant new personnel join the survey operations before work commences.
3. The acoustic source must be deactivated when not acquiring data or preparing to acquire data, except as necessary for testing. Unnecessary use of the acoustic source shall be avoided. Notified operational capacity (not including redundant backup airguns) must not be exceeded during the survey, except where unavoidable for source testing and calibration purposes. All occasions where activated source volume exceeds notified operational capacity must be communicated to the PSO(s) on duty and fully documented. The lead PSO must be granted access to relevant instrumentation documenting acoustic source power and/or operational volume.

Protected Species Observers (PSOs, Visual and Acoustic)

Qualifications

1. The MMPA authorization (as applicable) and BOEM-approved Permit/Plan holder must use independent, dedicated, trained visual and acoustic PSOs, meaning that the PSOs must be employed by a third-party observer provider, may have no tasks other than to conduct observational effort (visual or acoustic), collect data, and communicate with and instruct relevant vessel crew with regard to the presence of protected species and mitigation requirements (including brief alerts regarding maritime hazards), and must have successfully completed an approved PSO training course appropriate for their designated task (visual or acoustic). Acoustic PSOs are required to complete specialized training for operating PAM systems and are encouraged to have familiarity with the vessel with which they will be working. PSOs can act as acoustic or visual observers (but not at the same time) as long as they demonstrate to NMFS (nmfs.psoreview@noaa.gov) that their training and experience are sufficient to perform necessary tasks. NMFS must review and approve PSO resumes accompanied by a relevant training course information packet that includes the name and qualifications (i.e., experience, training completed, or educational background) of the instructor(s), the course outline or syllabus, and course reference material as well as a document stating successful completion of the course. NMFS shall have one week to approve PSOs from the time that the necessary information is submitted by the BOEM-approved Permit/Plan holder, after which PSOs meeting the minimum requirements shall automatically be considered approved.
2. NMFS approves PSOs as conditional or unconditional. A conditionally-approved PSO may be one who is trained but has not yet attained the relevant experience, or who has attained the necessary level of experience but not in the particular region. An unconditionally-approved PSO is one who has attained the necessary experience within the relevant region. At least one of the visual and two of the acoustic PSOs aboard the vessel must have a minimum of 90 days at-sea experience working in those roles, respectively, during a deep penetration seismic survey, with no more than 18 months elapsed since the conclusion of the at-sea experience. One visual PSO with such experience shall be designated as the lead for the entire protected species observation team. The lead shall coordinate duty schedules and roles for the PSO team and serve as primary point of contact for the vessel operator. To the maximum extent practicable, the lead PSO shall devise the duty schedule such that experienced PSOs are on duty with those PSOs with appropriate training but who have not yet gained relevant experience.
    a. PSOs must successfully complete relevant training, including completion of all required coursework and passing (80 percent or greater) a written and/or oral examination developed for the training program. PSOs must have successfully attained a bachelor's degree from an accredited college or university with a major in one of the natural sciences, a minimum of 30 semester hours or

equivalent in the biological sciences, and at least one undergraduate course in math or statistics. The educational requirements may be waived if the PSO has acquired the relevant skills through alternate experience. Requests for such a waiver shall be submitted by the BOEM-approved Permit/Plan holder to NMFS (nmfs.psoreview@noaa.gov) and must include written justification. Requests shall be granted or denied (with justification) by NMFS within one week of receipt of submitted information. Alternate experience that may be considered includes, but is not limited to: (1) secondary education and/or experience comparable to PSO duties; (2) previous work experience conducting academic, commercial, or government-sponsored protected species surveys; or (3) previous work experience as a PSO; the PSO should demonstrate good standing and consistently good performance of PSO duties.

Equipment

The MMPA incidental take authorization (as applicable) and BOEM-approved Permit/Plan holder is required to:

1. Provide PSOs with bigeye binoculars (e.g., 25 x 150; 2.7 view angle; individual ocular focus; height control) of appropriate quality solely for PSO use. These shall be pedestal-mounted on the deck at the most appropriate vantage point that provides for optimal sea surface observation, PSO safety, and safe operation of the vessel.
2. Work with the selected third-party observer provider to ensure PSOs have all equipment (including backup equipment) needed to adequately perform necessary tasks, including accurate determination of distance and bearing to observed protected species. Such equipment, at a minimum, shall include:
    a. Each vessel requiring PAM will include a passive acoustic monitoring system that has been verified and tested by an experienced acoustic PSO that will be using it during the trip for which monitoring is required.
    b. Reticle binoculars (e.g., 7 x 50) of appropriate quality (at least one per PSO, plus backups)
    c. Global Positioning Units (GPS) (plus backup)
    d. Digital camera with a telephoto lens (the camera or lens should also have an image stabilization system) that is at least 300 mm or equivalent on a full-frame single lens reflex (SLR) (plus backup)Radios for communication among vessel crew and PSOs (at least one per PSO, plus backups)
    e. Any other tools necessary to adequately perform necessary PSO tasks.

    Equipment specified in (a) through (g) above may be provided by an individual PSO, the third-party observer provider, or the MMPA authorization (as applicable) and BOEM-approved Permit/Plan holder but the latter is responsible for ensuring PSOs have the proper equipment required to perform the duties specified within these protocols.

Visual Monitoring

1. During survey operations (e.g., any day on which use of the acoustic source is planned to occur, and whenever the acoustic source is in the water, whether activated or not), a minimum of two visual PSOs must be on duty and conducting visual observations at all times during daylight hours (i.e., from 30 minutes prior to sunrise through 30 minutes following sunset).
2. Visual monitoring of the exclusion and buffer zones must begin no less than 30 minutes prior to ramp-up and must continue until one hour after use of the acoustic source ceases or until 30 minutes past sunset.
3. Visual PSOs shall coordinate to ensure 360° visual coverage around the vessel from the most appropriate observation posts, and shall conduct visual observations using binoculars and the naked eye while free from distractions and in a consistent, systematic, and diligent manner.
4. PSOs shall establish and monitor applicable exclusion and buffer zones. These zones shall be based upon the radial distance from the edges of the airgun array (rather than being based on the center of the array or around the vessel itself). During use of the acoustic source (i.e., anytime the acoustic source is active, including ramp-up), occurrences of protected species within the buffer zone (but outside the exclusion zone) should be communicated to the operator to prepare for the potential shutdown for marine mammals (or voluntary pause for other non-marine mammal protected species [e.g., sea turtles] if being employed) of the acoustic source.
5. Visual PSOs shall immediately communicate all observations to the on duty acoustic PSO(s), including any determination by the PSO regarding species identification, distance, and bearing and the degree of confidence in the determination.
6. Any observations of protected species by crew members aboard any vessel associated with the survey shall be relayed to the PSO team.
7. During good conditions (e.g., daylight hours; Beaufort sea state (BSS) 3 or less), visual PSOs shall conduct observations when the acoustic source is not operating for comparison of sighting rates and behavior with and without use of the acoustic source and between acquisition periods, to the maximum extent practicable.
8. Visual PSOs may be on watch for a maximum of two consecutive hours followed by a break of at least one hour between watches and may conduct a maximum of 12 hours of observation per 24-hour period. Combined observational duties (visual and acoustic but not at same time) may not exceed 12 hours per 24-hour period for any individual PSO.

Acoustic Monitoring

1. Applicants must provide a PAM plan to NMFS according to the MMPA authorization

including description of the hardware and software proposed for use prior to proceeding with any survey where PAM is required. The source vessel must use a towed PAM system at all times when operating in waters deeper than 100 m, which must be monitored by at a minimum one on duty acoustic PSO beginning at least 30 minutes prior to ramp-up and at all times during use of the acoustic source. "PAM system" refers to calibrated hydrophone arrays with full system redundancy to detect, identify, and estimate distance and bearing to vocalizing cetaceans. The PAM system must have at least one calibrated hydrophone (per each deployed hydrophone type and/or set) sufficient for determining whether background noise levels on the towed PAM system are sufficiently low to meet performance expectations, and must incorporate appropriate hydrophone elements (1 Hz to 180 kHz range) and sound data acquisition card technology for sampling relevant frequencies (*i.e.*, to 360 kHz). Applicants must provide a PAM plan including description of the hardware and software proposed for use prior to proceeding with any survey where PAM is required.

2. Acoustic PSOs shall immediately communicate all detections to visual PSOs, when visual PSOs are on duty, including any determination by the PSO regarding species identification, distance, and bearing and the degree of confidence in the determination.
3. Acoustic PSOs may be on watch for a maximum of four consecutive hours followed by a break of at least two hours between watches and may conduct a maximum of 12 hours of observation per 24-hour period. Combined observational duties (acoustic and visual but not at same time) may not exceed 12 hours per 24-hour period for any individual PSO.
4. Survey activity may continue for 30 minutes when the PAM system malfunctions or is damaged, while the PAM operator diagnoses the issue. If the diagnosis indicates that the PAM system must be repaired to solve the problem, operations may continue for an additional two hours without acoustic monitoring during daylight hours only under the following conditions:
    a. Sea state is less than or equal to BSS 4;
    b. No marine mammals (excluding delphinids) detected solely by PAM in the applicable exclusion zone in the previous two hours;
    c. NMFS and BSEE are notified via email (nmfs.psoreview@noaa.gov and protectedspecies@bsee.gov, respectively) as soon as practicable with the time and location in which operations began occurring without an active PAM system; and
    d. Operations with an active acoustic source, but without an operating PAM system, do not exceed a cumulative total of four hours in any 24-hour period.

Data Collection

PSOs must use a standardized data collection form, whether hard copy or electronic. PSOs shall record detailed information about any implementation of mitigation requirements,

including the distance of animals to the acoustic source and description of specific actions that ensued, the behavior of the animal(s), any observed changes in behavior before and after implementation of mitigation, and if shutdown was implemented, the length of time before any subsequent ramp-up of the acoustic source. If required mitigation was not implemented, PSOs should record a description of the circumstances. At a minimum, the following information must be recorded within the interim reports:

1. BOEM Permit/Plan number;
2. Vessel names (source vessel and other vessels associated with survey), vessel size and type, maximum speed capability of vessel, port of origin, and call signs;
3. PSO names and affiliations;
4. Dates of departures and returns to port with port name;
5. Date and participants of PSO briefings (as discussed in General Requirements. 2.);
6. Dates and times (Greenwich Mean Time) of survey effort and times corresponding with PSO effort;
7. Vessel location (latitude/longitude) when survey effort began and ended and vessel location at beginning and end of visual PSO duty shifts;
8. Vessel heading and speed at beginning and end of visual PSO duty shifts and upon any line change;
9. Environmental conditions while on visual survey (at beginning and end of PSO shift and whenever conditions changed significantly), including BSS and any other relevant weather conditions including cloud cover, fog, sun glare, and overall visibility to the horizon;
10. Factors that may have contributed to impaired observations during each PSO shift change or as needed as environmental conditions changed (e.g., vessel traffic, equipment malfunctions);
11. Survey activity information, such as acoustic source power output while in operation, number and volume of airguns operating in the array, tow depth of the array, and any other notes of significance (i.e., pre-clearance, ramp-up, shutdown, testing, shooting, ramp-up completion, end of operations, streamers, etc.); and
12. Upon visual observation of any protected species, the following information:
    a. Watch status (sighting made by PSO on/off effort, opportunistic, crew, alternate vessel/platform);
    b. PSO who sighted the animal;
    c. Time of sighting;
    d. Vessel location at time of sighting;
    e. Water depth;
    f. Direction of vessel's travel (compass direction);
    g. Direction of animal's travel relative to the vessel;
    h. Pace of the animal;
    i. Estimated distance to the animal and its heading relative to vessel at

initial sighting;

j. Identification of the animal (e.g., genus/species, lowest possible taxonomic level, or unidentified) and the composition of the group if there is a mix of species;
k. Estimated number of animals (high/low/best);
l. Estimated number of animals by cohort (adults, juveniles,, group composition, etc.);
m. Description (as many distinguishing features as possible of each individual seen, including length, shape, color, pattern, scars or markings, shape and size of dorsal fin, shape of head, and blow characteristics);
n. Detailed behavior observations (e.g., number of blows/breaths, number of surfaces, breaching, spyhopping, diving, feeding, traveling; as explicit and detailed as possible; note any observed changes in behavior), including an assessment of behavioral responses to survey activity;
o. Animal's closest point of approach (CPA) and/or closest distance from any element of the acoustic source;
p. Platform activity at time of sighting (e.g., deploying, recovering, testing, shooting, data acquisition, other); and
q. Description of any actions implemented in response to the sighting (e.g., delays, shutdown, ramp-up) and time and location of the action.

13. If a marine mammal is detected while using the PAM system, the following information should be recorded:
    a. An acoustic encounter identification number, and whether the detection was linked with a visual sighting;
    b. Date and time when first and last heard;
    c. Types and nature of sounds heard (e.g., clicks, whistles, creaks, burst pulses, continuous, sporadic, strength of signal);
    d. Any additional information recorded such as water depth of the hydrophone array, bearing of the animal to the vessel (if determinable), species or taxonomic group (if determinable), spectrogram screenshot, and any other notable information.

Seismic Survey Protocols[1]

Pre-clearance and Ramp-up

The intent of pre-clearance observation (30 minutes) is to ensure no protected species are observed within the exclusion zones, and buffer zone if applicable (i.e., only when the exclusion zone is equal to 500 meters, see Definitions section for details on when the buffer

[1] This includes borehole or vertical seismic profile surveys.

zone is not applicable), prior to the beginning of ramp-up. During pre-clearance is the only time observations of protected species in the buffer zone would prevent operations (i.e., the beginning of ramp-up). The intent of ramp-up is to warn protected species of pending seismic operations and to allow sufficient time for those animals to leave the immediate vicinity. A ramp-up procedure, involving a step-wise increase in the number of airguns firing and total array volume until all operational airguns are activated and the full volume is achieved, is required at all times as part of the activation of the acoustic source. All operators must adhere to the following pre-clearance and ramp-up requirements, which are applicable to both marine mammals and sea turtles:

1. The operator must notify a designated PSO of the planned start of ramp-up as agreed upon with the lead PSO; the notification time should not be less than 60 minutes prior to the planned ramp-up in order to allow the PSOs time to monitor the exclusion and buffer zones for 30 minutes prior to the initiation of ramp-up (pre-clearance).
2. Ramp-ups shall be scheduled so as to minimize the time spent with the source activated prior to reaching the designated run-in.
3. One of the PSOs conducting pre-clearance observations must be notified again immediately prior to initiating ramp-up procedures and the operator must receive confirmation from the PSO to proceed.
4. Ramp-up may not be initiated if any marine mammal or sea turtle is within the applicable exclusion or buffer zone. If a marine mammal or sea turtle is observed within the applicable exclusion zone or the buffer zone during the 30 minute pre-clearance period, ramp-up may not begin until the animal(s) has been observed exiting the zones or until an additional time period has elapsed with no further sightings (15 minutes for small odontocetes and 30 minutes for all other species including sea turtles).
5. Ramp-up shall begin by activating a single airgun of the smallest volume in the array and shall continue in stages by doubling the number of active elements at the commencement of each stage, with each stage of approximately the same duration. Duration shall not be less than 20 minutes. The operator must provide information to the PSO documenting that appropriate procedures were followed.
6. PSOs must monitor the exclusion and buffer zones during ramp-up, and ramp-up must cease and the source must be shut down upon observation of a marine mammal or sea turtle within the applicable exclusion zone. Once ramp-up has begun, observations of marine mammals and sea turtles within the buffer zone do not require shutdown, or voluntarily pause for other non-marine mammal protected species (e.g., sea turtles) if being employed, but such observation shall be communicated to the operator to prepare for the potential shutdown, or voluntarily pause if being employed.
7. Ramp-up may occur at times of poor visibility, including nighttime, if appropriate acoustic monitoring has occurred with no detections in the 30 minutes prior to beginning ramp-up. Acoustic source activation may only occur at times of poor

visibility where operational planning cannot reasonably avoid such circumstances.

8. If the acoustic source is shut down for brief periods (i.e., less than 30 minutes) for reasons other than that described below in *Shutdown* (e.g., mechanical difficulty), it may be activated again without ramp-up if PSOs have maintained constant visual and/or acoustic observation and no visual detections of marine mammals or sea turtles have occurred within the applicable exclusion zone and no acoustic detections of marine mammals have occurred. For any longer shutdown, pre-clearance observation and ramp-up are required. For any shutdown at night or in periods of poor visibility (e.g., BSS 4 or greater), ramp-up is required, but if the shutdown period was brief and constant observation was maintained, pre-clearance watch of 30 min is not required.
9. Testing of the acoustic source involving all elements requires ramp-up. Testing limited to individual source elements or strings does not require ramp-up but does require pre-clearance of 30 min.

Shutdown

For non-marine mammal protected species (e.g., sea turtles), shutdowns are not required. However, the BOEM Permit or authorized Plan and MMPA authorization (as applicable) holder may employ a voluntary pause during which the visual PSO would request that the operator voluntarily pause the airgun array for six shots if a non-marine mammal protected species is observed within the exclusion zone (within 500 meters) during active airgun use, to let the animal float past the array while it is inactive. For marine mammals, all operators must adhere to the following shutdown requirements:

1. Any PSO on duty has the authority to delay the start of survey operations or to call for shutdown of the acoustic source if a marine mammal is detected within the applicable exclusion zone.
2. The operator must establish and maintain clear lines of communication directly between PSOs on duty and crew controlling the acoustic source to ensure that shutdown, and voluntary pause commands (optional for other protected species) are conveyed swiftly while allowing PSOs to maintain watch.
3. When both visual and acoustic PSOs are on duty, all detections must be immediately communicated to the remainder of the on-duty PSO team for potential verification of visual observations by the acoustic PSO or of acoustic detections by visual PSOs.
4. When the airgun array is active (i.e., anytime one or more airguns is active, including during ramp-up) and (1) a marine mammal appears within or enters the applicable exclusion zone and/or (2) a marine mammal (excluding delphinids) is detected acoustically and localized within the applicable exclusion zone, the acoustic source must be shut down. When shutdown is called for by a PSO, the acoustic source must be immediately deactivated and any dispute resolved only following deactivation.
5. The shutdown requirement is waived for dolphins of the following genera: *Steno*, *Tursiops*, *Stenella*, and *Lagenodelphis*.

a. If a small delphinid (individual of the Family Delphinidae, which includes the aforementioned dolphin genera), is acoustically detected and localized within the exclusion zone, no shutdown is required unless the acoustic PSO or a visual PSO confirms the individual to be of a genera other than those listed above, in which case a shutdown is required.

6. If there is uncertainty regarding identification (i.e., whether the observed marine mammal(s) belongs to one of the delphinid genera for which shutdown is waived or one of the species with a larger exclusion zone), visual PSOs may use best professional judgment in making the decision to call for a shutdown.
7. Upon implementation of shutdown, the source may be reactivated after the marine mammal(s) has been observed exiting the applicable exclusion zone (i.e., animal is not required to fully exit the buffer zone where applicable) or following a 30-minute clearance period with no further observation of the marine mammal(s).

Shallow penetration protocols

1. Shallow penetration surveys are defined as surveys using airgun arrays with total volume equal to or less than 400 in^3, single airguns, boomers, or equivalent sources.
2. LOA-holders shall follow the requirements defined for deep penetration surveys at § 217.184(b), with the following exceptions:
    a. PAM is not required for shallow penetration surveys.
    b. Ramp-up for small airgun arrays must follow the procedure described above for large airgun arrays, but may occur over an abbreviated period of time. Ramp-up is not required for surveys using only a single airgun. For sub-bottom profilers, power should be increased as feasible to effect a ramp-up.
    c. Two exclusion zones are defined, depending on the species and context. A standard exclusion zone encompassing the area at and below the sea surface out to a radius of 100 meters from the edges of the airgun array (if used) or from the acoustic source (0-100 m) is defined. For special circumstances (§ 217.184(b)(6)(v)), the exclusion zone encompasses an extended distance of 500 meters (0-500 m).
    d. The buffer zone encompasses the area at and below the sea surface from the edge of the 0-100 meter exclusion zone out to a radius of 200 meters from the edges of the airgun array (if used) or from the acoustic source (100-200 meters). The buffer zone is not applicable when the exclusion zone is greater than 100 meters.

Non-Airgun High-Resolution Geophysical (HRG) Protocol

Non-airgun HRG surveys are conducted in leases and along pipeline routes to evaluate the potential for geohazards, archaeological resources, and certain types of benthic communities. Non-airgun HRG sources include but are not limited to side-scan sonars, boomers, sparkers (in limited situations) and compressed high-intensity radiated pulse (CHIRP) subbottom profilers (in limited situations), and single-beam or multibeam depth sounders.

Non-Airgun HRG Surveys with Frequencies ≥180 kHz

Acoustic sources do not require detailed analyses because the frequency is outside the general hearing range of marine mammals.

Non-Airgun HRG Surveys with Frequencies <180 kHz

For all non-airgun HRG surveys in which one or more active acoustic sound sources are operating at these frequencies, the following will be required for the indicated water depths. PAM is not required for any HRG survey. No shutdowns would be required for HRG surveys. Pre-clearance watch is required for a period of 30 minutes and over a 200-m radius from the acoustic source.

Shallow-water (< 100 m)

1. Employ a minimum of one visual PSO, which may be a crew member. PSOs employed during shallow-water HRG surveys are only required during a pre-clearance period.

Deep-water (> 100 m)

1. Employ a minimum of one independent visual PSO during all daylight operations, in the same manner as was described for deep and shallow airgun penetration surveys.
2. PSOs are not required during survey operations in which the active acoustic source(s) are deployed on an autonomous underwater vehicle.

Entanglement and Entrainment Risk Reduction

All lines (rope, chain, cable, etc.) associated with geophysical surveys must be stiff, taut, and non-looping. Flexible lines such as nylon or polypropylene that could loop or tangle protected species must be enclosed in a sleeve to add rigidity and prevent looping or tangling. No excess underwater line is allowed. All equipment, especially towed apparatuses (e.g., tail buoys), shall be designed in a way as to prevent entrainment of sea turtles or other protected species.

Nodal Survey Requirements

To avoid the risk of entanglement, lessees and operators conducting surveys using ocean-bottom

nodes or similar gear must:

1. Use negatively buoyant coated wire-core tether cable;
2. Ensure any cables/lines are designed to be rigid ;
3. Retrieve all lines immediately following completion of the survey; and
4. Attach acoustic pingers directly to the coated tether cable; acoustic releases should not be used.

Reporting

1. The BOEM Permit/Plan holder shall submit interim reports (see Data Collection section for details) on the 1st of each month to BSEE (protectedspecies@bsee.gov) detailing all protected species observations with closest approach distance.
2. The MMPA authorization (as applicable) and BOEM Permit/Plan holder shall submit a draft comprehensive report to BOEM/BSEE (protectedspecies@boem.gov and protectedspecies@bsee.gov) and NMFS (nmfs.psoreview@noaa.gov) on all activities and monitoring results within 90 days of the completion of the survey or expiration of the MMPA authorization (as applicable) or BOEM Permit/Plan, whichever comes sooner, or if an issued MMPA authorization is valid for greater than one year, the summary report must be submitted on an annual basis,. The report must describe all activities conducted and sightings of protected species near the activities, must provide full documentation of methods, results, and interpretation pertaining to all monitoring, and must summarize the dates and locations of survey operations and all protected species sightings (dates, times, locations, activities, associated survey activities, and information regarding locations where the acoustic source was used). The draft report shall also include geo-referenced time-stamped vessel tracklines for all time periods during which airguns were operating. Tracklines should include points recording any change in airgun status (e.g., when the airguns began operating, when they were turned off, or when they changed from full array to single gun or vice versa). GIS files shall be provided in ESRI shapefile format and include the UTC date and time, latitude in decimal degrees, and longitude in decimal degrees. All coordinates shall be referenced to the WGS84 geographic coordinate system. In addition to the report, all raw observational data shall be made available to BOEM/BSEE and NMFS. The report must summarize the information submitted in interim monthly reports as well as additional data collected as described above in *Data Collection* and the MMPA authorization (as applicable). The draft report must be accompanied by a certification from the lead PSO as to the accuracy of the report, and the lead PSO may submit directly to BOEM/BSEE and NMFS a statement concerning implementation and effectiveness of the required mitigation and monitoring. A final report must be submitted within 30 days following resolution of any comments on the draft report.

3. Reporting injured or dead protected species:
   The MMPA authorization (as applicable) and BOEM Permit/Plan holder must report sightings of any injured or dead aquatic protected species immediately, regardless of the cause of injury or death.

   For injured or dead non-marine mammal aquatic protected species, report incidents to the hotlines listed at https://www.fisheries.noaa.gov/report (phone numbers vary by state). For reporting dead or injured marine mammals, refer to the reporting requirements specified in the MMPA authorization (as applicable), associated with the activity being conducted. The report must include the following information:

   1. Time, date, water depth and location (latitude/longitude) of the first discovery (and updated location information if known and applicable);
   2. Relevant weather conditions (e.g., cloud cover, fog, sun glare, etc.);
   3. Name, type, call sign, and speed of the vessel during and leading up to the first sighting;
   4. Species identification (if known) or description of the animal(s) involved;
   5. Condition of the animal(s) (including carcass condition if the animal is dead);
   6. Observed behaviors of the animal(s), if alive;
   7. If available, photographs or video footage of the animal(s); and
   8. General circumstances under which the animal was discovered.

References

Baker, K., D. Epperson, G. Gitschlag, H. Goldstein, J. Lewandowski, K. Skrupky, B. Smith, and T. Turk. 2013. National standards for a protected species observer and data management program: A model using geological and geophysical surveys. Technical Memorandum NMFS-OPR-49, Office of Protected Resources, National Marine Fisheries Service, National Oceanic and Atmospheric Administration; Bureau of Ocean Energy Management, U.S. Department of the Interior; Bureau of Safety and Environmental Enforcement, U.S. Department of the Interior, Silver Spring, Maryland.

Appendix B. Gulf of Mexico Marine Trash and Debris Awareness and Elimination Survey Protocols

These protocols will be implemented by the Bureau of Ocean Energy Management (BOEM), the Bureau of Safety and Environmental Enforcement (BSEE), and operators in complying with the Endangered Species Act (ESA; 16 U.S.C. §§ 1531-1544) and Marine Mammal Protection Act (MMPA; 16 U.S.C. §§1361- 1423h).

Background

Marine trash and debris pose a threat to fish, marine mammals, sea turtles, and potentially other marine animals; cause costly delays and repairs for commercial and recreational boating interests; detract from the aesthetic quality of recreational shore fronts; and increase the cost of beach and park maintenance. As Outer Continental Shelf (OCS) oil- and gas-related activities expand into deeper waters, the number of species of protected marine animals exposed to marine debris could increase. Many marine species are protected under the Endangered Species Act (ESA) and all marine mammals (including manatees) are protected under the Marine Mammal Protection Act (MMPA). The discharge of garbage and debris has been the subject of strict laws, such as MARPOL-Annex V and the Marine Debris Act, 33 U.S.C. 1951 *et seq.*, and regulations imposed by various agencies including the United States Coast Guard and the Environmental Protection Agency.

Since OCS oil and gas operations in the Gulf of Mexico may contribute to this problem, 30 CFR 250.300(a) and (b)(6) prohibit discharging containers and other materials into the marine environment, and 30 CFR 250.300(c) and (d) require durable identification markings on skid-mounted equipment, portable containers, spools or reels, and drums, and to record and report such items when lost overboard to the District Manager through facility daily operations reports. Therefore, in accordance with 30 CFR 250.300(a) and (b)(6), exercise special caution when handling and transporting small items and packaging materials, particularly those made of non-biodegradable, environmentally persistent materials such as plastic or glass that can be lost in the marine environment and washed ashore. Increasing awareness of the problem and emphasizing offshore worker's responsibilities will help minimize the litter issue and control the unintended loss of items such as empty buckets, hard hats, shrink wrap, strip lumber and pipe thread protectors.

BSEE and BOEM consult jointly with the National Marine Fisheries Service (NMFS) and the U.S. Fish and Wildlife Service (FWS) under Section 7 of the ESA to ensure that BOEM or BSEE authorized activities do not jeopardize the continued existence of ESA-listed species nor result in adverse modification of designated critical habitat. Incidental take of ESA-listed species is prohibited except as authorized pursuant to an Incidental Take Statement in a Biological Opinion. Incidental take of ESA listed marine mammals cannot be authorized

under the ESA unless also authorized under the MMPA.

Marine Trash and Debris Placards

Permit holders must continue to post placards that include each of the information text boxes in Attachment 1 of this Appendix in prominent places on all fixed and floating production facilities that have sleeping or food preparation capabilities and on mobile drilling units engaged in oil and gas operations in the Gulf of Mexico OCS. Each of the placards depicted, with the language specified, must be displayed on a 5x8 inch format or larger. These signs must be displayed at line-of-sight height at or near boat landings and heliports; in mess areas; and in the recreation, training or orientation areas. One or more areas may be omitted if there is insufficient space. These notices must be referenced, and their contents explained, during any initial orientation given on the facility for visitors or occupants. Placards must be sturdy enough to withstand the local environment and must be replaced when damage or wear compromises readability.

Marine Trash and Debris Awareness Training

All OCS offshore employees and those contractors actively engaged in OCS offshore operations (e.g., wireline operators, contract lease operators, and maintenance or construction crews) should complete marine trash and debris awareness training annually.

The training for employees and contractors consists of two parts: (1) viewing a marine trash and debris training video or slide show (described below); and (2) receiving an explanation from management personnel of the lessee or designated lease operator that emphasizes their commitment to the requirements.

You may obtain the marine trash and debris training video, training slide packs, and other marine debris related educational material produced by the Offshore Operators Committee (OOC), through the OOC website at https://www.ooctraining.org/ or https://www.bsee.gov/debris. The video and slides are offered in English and Spanish versions and the video is available as a DVD or VHS tape. The video, slides, and related material may also be downloaded directly from the website.

Marine Trash and Debris Awareness Training and Certification Process

Permit holders and offshore operators must continue to develop and use a marine trash and debris awareness training and certification process that reasonably assures that the employees and contractors specified above are in fact trained. Your training process must include the following elements:

1) viewing of either the video or the slide show by the personnel specified above using one of the following methods:
   a) attendance at periodic meetings held for this purpose;
   b) as part of several scheduled training components;
   c) web-based training with email notification; or
   d) training by a third-party contractor;
2) an explanation from the management that conveys the commitment of the company to achieve the objectives of the trash and debris containment requirement;
3) attendance measures (initial and annual); and
4) recordkeeping and availability of records for inspection by BSEE.

By January 31st of each year, you must provide BSEE and NMFS with an annual report (1-2 pages) signed by a company official that describes your marine trash and debris awareness training process and certifies that the training process has been followed for the previous calendar year. You should send the report by email to marinedebris@bsee.gov[1].

In lieu of emailing the report, you may send a printed copy to:

Bureau of Safety and Environmental Enforcement
Gulf of Mexico OCS Region
Office of Environmental Compliance (MS GE466)
1201 Elmwood Park Blvd.
New Orleans, Louisiana 70123

Contact

Please submit any questions by e-mail to: marinedebris@bsee.gov.

[1] BSEE will forward these reports to NMFS per the requirements under this biological opinion.

Attachment 1

Marine Debris Placards

WHAT IS MARINE DEBRIS?

Marine debris is any object or fragment of wood, metal, glass, rubber, plastic, cloth, paper or any other man-made item or material that is lost or discarded in the marine environment. Marine debris may be intentionally dumped, accidentally dropped, or indirectly deposited. Whatever the source, marine debris is a direct result of human activities on land and at sea. Depending upon its composition, marine debris may sink to the seafloor, drift in the water column, or float on the surface of the sea. Certain debris, such as plastics, can persist for hundreds of years in the marine environment without decomposing.

WARNING!

YOUR ACTIONS MAY SUBJECT YOU TO SEVERE LEGAL CONSEQUENCES!

The disposal and/or discharge of any solid waste anywhere in the marine environment (other than ground-up food particles) is strictly prohibited by U.S. Coast Guard and Environmental Protection Agency regulations. THIS INCLUDES MATERIALS OR DEBRIS ACCIDENTALLY LOST OVERBOARD.

The disposal of equipment, cables, chains, containers or other materials into offshore waters is prohibited by the Bureau of Safety and Environmental Enforcement (30 CFR 250.300(b)(6)). THIS INCLUDES MATERIALS OR DEBRIS ACCIDENTALLY LOST OVERBOARD.

ATTENTION!

MARINE DEBRIS MAY CAUSE SEVERE ECOLOGICAL DAMAGE!

Marine debris discarded or lost from offshore and coastal sources may injure or kill fish, marine mammals, sea turtles, seabirds and other wildlife.

Thousands of marine animals, including marine mammals, sea turtles and seabirds, die every year from entanglement in fishing line, strapping bands, discarded ropes and nets and plastic six-pack rings. Additionally, unknown numbers of marine animals die each year from internal injury, intestinal blockage and starvation as a result of ingesting marine debris.

Marine debris fouls boat propellers and clogs water intake ports on engines thereby endangering the safety of fishermen and boaters and resulting in heavy loss of time and money.

Marine debris detracts from the aesthetic quality of recreational beaches and shorelines and increases the cost of park and beach maintenance.

ATTENTION!

SECURE ALL LOOSE ARTICLES!

NOAA Fisheries now expects petroleum industry personnel to pick up and recover any articles lost overboard from boats and offshore structures as safety conditions permit. Additionally, 30 CFR 250.300 (d) requires recording and reporting items lost overboard to the District Manager through facility daily operations reports.

Protect marine animals, as well as your valuable time and money, by doing the following to prevent accidental loss of these items:

Properly securing all materials, equipment, and personal belongings. Articles such as hardhats, life vests, sunglasses, cigarette lighters, parts bags, buckets, shrink wrap, strip lumber, and pipe thread protectors become marine debris when lost overboard.

Making sure that all trash receptacles have tight fitting lids and that the lids are used.

Providing and using secure cigarette butt containers. Cigarette butts are one of the most common forms of marine debris. Many cigarette butts contain some form of plastic and do not decompose in the ocean. Cigarette butts pose a major threat to marine wildlife as they resemble food and cause gut blockages and starvation when ingested.

Do your part to eliminate marine debris. Encourage others to be responsible about marine debris by making suggestions to secure potential marine debris on your boat or structure or by participating in a beach cleanup.

Appendix C. Gulf of Mexico Vessel Strike Avoidance and Injured/Dead Aquatic Protected Species Reporting Protocols

These protocols will be implemented by the Bureau of Ocean Energy Management (BOEM), the Bureau of Safety and Environmental Enforcement (BSEE), and provide guidelines to operators in complying with the Endangered Species Act (ESA; 16 U.S.C. §§ 1531-1544) and Marine Mammal Protection Act (MMPA; 16 U.S.C. §§1361- 1423h). The measures contained herein apply to all vessels associated with the federally regulated oil and gas program in the Gulf of Mexico.

Aquatic Protected Species Identification

Crew and supply vessel personnel should use a Gulf of Mexico reference guide that includes identifying information on marine mammals, sea turtles, and other marine protected species (i.e., Endangered Species Act listed species such as Gulf sturgeon, giant manta ray, or oceanic whitetip shark; hereafter collectively termed "other aquatic protected species") that may be encountered in the Gulf of Mexico Outer Continental Shelf (OCS). Vessel operators must comply with the below measures except under extraordinary circumstances when the **safety of the vessel or crew is in doubt or the safety of life at sea is in question**.

Vessel Strike Avoidance

1. Vessel operators and crews must maintain a vigilant watch for all aquatic protected species and slow down, stop their vessel, or alter course, as appropriate and regardless of vessel size, to avoid striking any protected species. A single aquatic protected species at the surface may indicate the presence of submerged animals in the vicinity of the vessel; therefore, precautionary measures should always be exercised. A visual observer aboard the vessel must monitor a vessel strike avoidance zone (species-specific distances detailed below) around the vessel according to the parameters stated below, to ensure the potential for strike is minimized. Visual observers monitoring the vessel strike avoidance zone can be either third-party observers or crew members (e.g., captain), but crew members responsible for these duties must be provided sufficient training to distinguish aquatic protected species to broad taxonomic groups, as well as those specific species detailed further below.
2. Vessel speeds must also be reduced to 10 knots or less when mother/calf pairs, pods, or large assemblages (greater than three) of any marine mammal are observed near a vessel.
3. All vessels must maintain a minimum separation distance of 100 meters (m) from

sperm whales, and 500 m from any baleen whale to specifically protect the Gulf of Mexico Bryde's. If a large whale species is unidentifiable, then the vessel/observer/crew should act upon their actions per these mitigations as if it is a baleen whale.

4. All vessels must, to the maximum extent practicable, attempt to maintain a minimum separation distance of 50 meters from all "other aquatic protected species" including sea turtles, with an exception made for those animals that approach the vessel.
5. When aquatic protected species are sighted while a vessel is underway, the vessel should take action as necessary to avoid violating the relevant separation distance (e.g., attempt to remain parallel to the animal's course, avoid excessive speed or abrupt changes in direction until the animal has left the area). If aquatic protected species are sighted within the relevant separation distance, the vessel should reduce speed and shift the engine to neutral, not engaging the engines until animals are clear of the area. This does not apply to any vessel towing gear (e.g., source towed array and site clearance trawling).
6. If a manatee is sighted, vessels associated with the project should operate at "no wake/idle" speeds within that area. Vessels should follow routes of deep water whenever possible and attempt to maintain a distance of 50 m if practicable. This does not apply to any vessel towing gear (e.g., source towed array and site clearance trawling).
7. Any BOEM/BSEE-authorized or -permitted activity occurring within the Eastern Planning Area will be subject to a step-down review with NMFS under the attached 2020 biological opinion on BOEM Oil and Gas Program Activities in the Gulf of Mexico.

The above requirements do not apply in any case where compliance would create an imminent and serious threat to a person or vessel or to the extent that a vessel is restricted in its ability to maneuver and, because of that restriction, is unable to comply.

Injured/Dead Protected Species Reporting

Vessel operators must report sightings of any injured or dead aquatic protected species immediately, regardless of whether the injury or death is caused by your vessel. If the injury or death was caused by a collision with the operator's vessel, an entrapment within the operator's equipment or vessel (e.g. moon pool), or an entanglement within the operator's equipment, the operator must further notify BOEM and BSEE within 24 hours of the strike or entrapment/entanglement by email to protectedspecies@boem.gov and protectedspecies@bsee.gov[1].

[1] BOEM/BSEE will forward these reports to NMFS ESA section 7 biologist per reporting requirements under the attached biological opinion terms and conditions.

For injured or dead non-marine mammal aquatic protected species, report incidents to the hotlines listed at https://www.fisheries.noaa.gov/report (phone numbers vary by state). For reporting dead or injured marine mammals, refer to the reporting requirements specified in the MMPA authorization (as applicable), associated with the activity being conducted. The report must include the following information:

1. Time, date, water depth and location (latitude/longitude) of the first discovery (and updated location information if known and applicable);
2. Relevant weather conditions (e.g., cloud cover, fog, sun glare, etc.);
3. Name, type, call sign, and speed of the vessel during and leading up to the first sighting;
4. Species identification (if known) or description of the animal(s) involved;
5. Condition of the animal(s) (including carcass condition if the animal is dead);
6. Observed behaviors of the animal(s), if alive;
7. If available, photographs or video footage of the animal(s); and
8. General circumstances under which the animal was discovered.

Appendix D. Fisheries Take of Turtles

Table A- 1. Summary of Anticipated 3-year Take and Mortality Estimates for the Coastal Migratory Pelagic Resources in the Atlantic and Gulf of Mexico (NMFS 2015).

Species	Take	Total
Green sea turtle North Atlantic DPS	Total	31
	Lethal	9
Loggerhead sea turtle NWA DPS	Total	27
	Lethal	7
Kemp's ridley sea turtle	Total	8
	Lethal	2
Hawksbill sea turtle	Total	1
	Lethal	1
Leatherback sea turtle	Total	1
	Lethal	1
Smalltooth sawfish	Total	1
	Lethal	0
Atlantic sturgeon GM DPS	Total	2 (12)
	Lethal	0
Atlantic sturgeon NYB DPS	Total	4 (12)
	Lethal	0
Atlantic sturgeon CB DPS	Total	3 (12)
	Lethal	0
Atlantic sturgeon Carolina DPS	Total	4 (12)
	Lethal	0
Atlantic sturgeon SA DPS	Total	10 (12)
	Lethal	0

Table A- 2. Anticipated takes over 3-years for the Highly Migratory Species Atlantic Shark and Smoothhound Fisheries (NMFS 2012).

Sea Turtles	Non-Lethal Take	Lethal Take	Total Estimated Take
Loggerhead	48	78	126
Green	24	33	57
Leatherback	9	9	18
Kemp's ridley	15	21	36
Hawksbill	9	9	18
Marine Fish	**Non-Lethal Take**	**Lethal Take**	**Total Estimated Take**
Smalltooth sawfish	25	7	32
Atlantic sturgeon	GOM DPS = 27	GOM DPS = 9	GOM DPS = 36
	NYB DPS = 129	NYB DPS = 30	NYB DPS = 159
	CB DPS = 36	CB DPS = 9	CB DPS = 45
	SA DPS = 51	SA DPS = 12	SA DPS = 63
	Carolina DPS = 12	Carolina DPS = 6	Carolina DPS = 18
	All DPSs = 255	All DPSs = 66	All DPSs = 321
GOM = Gulf of Maine, NYB = New York Bight, CB = Chesapeake Bay, and SA = South Atlantic.			

Table A- 3. Anticipated takes over 3-years for the Southeast U.S. Shrimp Fisheries in Federal Waters (NMFS 2014).

Species	Otter Trawl Interactions, Captures, and Mortalities	Try Net Interactions**, Captures, and Mortalities	Otter Trawl and Try Net Combined Interactions, Captures, and Mortalities
Atlantic Sturgeon [31]	1710 total interactions, including 222 captures of which 27 are expected to be lethal every three years*, with DPS limits as follows: • Gulf of Maine DPS ≤ 156 interactions, including 21 captures, of which 3 are expected to be lethal • New York Bight DPS ≤ 447 interactions, including 60 captures, of which 9 are expected to be lethal • Chesapeake Bay DPS ≤ 309 interactions, including 42 captures, of which 6 are expected to be lethal • Carolina DPS ≤ 498 interactions, including 66 captures, of which 9 are expected to be lethal • South Atlantic DPS ≤ 1353 interactions, including 177 captures, of which 21 are expected to be lethal	63total interactions, all resulting in capture and of which none are expected to be lethal every three years*, with DPS limits as follows: • Gulf of Maine DPS ≤ 6 interactions all resulting in captures, of which none are expected to be lethal • New York Bight DPS ≤ 18 capture, of which none are expected to be lethal • Chesapeake Bay DPS ≤ 12 interactions, all resulting in capture, of which none are expected to be lethal • Carolina DPS ≤ 21 interactions all resulting in capture, of which none are expected to be lethal • South Atlantic DPS ≤ 51 interactions all which resulting in capture, of which none are expected to be lethal	1773 total interactions, including 285 captures of which 27 are expected to be lethal every three years*, with DPS limits as follows: • Gulf of Maine DPS ≤ 162 interactions, including 27 captures, of which 3 are expected to be lethal • New York Bight DPS ≤ 465 interactions, including 66 captures, of which 9 are expected to be lethal • Chesapeake Bay DPS ≤ 312 interactions, including 54 captures, of which 6 are expected to be lethal • Carolina DPS ≤ 519 interactions, including 87 captures, of which 9 are expected to be lethal • South Atlantic DPS ≤ 1404 interactions, including 228 captures, of which 21 are expected to be lethal
Smalltooth Sawfish	288 (105) every three years	--	288 (105) every three years

*Incidental take will be monitored based on the 3-year running totals (e.g., 2012-2014, 2013-2015)
**All try net interactions result in captures

Table A- 4. Anticipated take over three years starting in 2010 under the Gulf Of Mexico Reef Fish Fishery Management Plan (NMFS 2011).

Species	Commercial Bottom Longline Takes (Mortalities)	Commercial Vertical Line Takes (Mortalities)	Recreational Vertical Line Takes (Mortalities)	Vessel Strike Takes- All Lethal	Entire Fishery Takes (Mortalities)
Loggerhead	644 (397)[A] 623 (384)[B]	77 (23)	254 (75)	90(90)	1065 (585)[A] 1044 (572)[B]
Kemp's ridley	3 (3)	22 (7)	74 (22)	9 (9)	108 (41)
Green	3 (3)	14 (4)	45 (14)	54 (54)	116 (75)
Leatherback	3 (3)	1 (1)	1 (1)	6 (6)	11 (11)
Hawksbill	3 (3)	1 (1)	2 (1)	3 (3)	9 (8)
Smalltooth sawfish	2 (0)	2 (0)	4 (0)	0 (0)	8 (0)

[A]=anticipated in 2010-2012; [B]=anticipated for all subsequent three-year running totals (i.e., 2011-2013, 2012-2014, 2013-2015, etc.).

Appendix E. Summary of Oil Industry Discharges to the OCS Authorized by USEPA General NPDES Permits

Section 402 of the Clean Water Act authorizes the EPA to issue NPDES permits to regulate discharges into the nation's waters. EPA will issue a permit if they determine that the proposed discharges will not result in unreasonable degradation. Factors for determining unreasonable degradation can be found at 40 CFR 125.122. The EPA's review of information provided for the issuance of general permits GMG290000 and GEG460000 has not resulted in a determination of degradation of the impacted waters. These permits considered the following discharges, restrictions, and monitoring requirements:

1. **Drilling fluids/muds** – Fluids that are pumped down the drill pipe to counteract formation pressure, remove drill cuttings, cool the drill bit, and support the bore hole. They are often referred to as drilling muds due to the addition of fine-grained solids, inorganic salts, and organic additives. There are two main types of drilling fluids: water-based fluids (WBF) and Non-aqueous based fluids (NABF) which include oil based fluids (OBF) and synthetic-based fluids (SBF). Drilling fluids often contain barite which is a source of cadmium and mercury, which have been shown to bio-accumulate in marine organisms.

   Restrictions: (1) The discharge of non-aqueous based drilling fluid is prohibited, except that which adheres to cuttings and small volume discharges. Non-aqueous base fluids may be used as a carrier fluid (transporter fluid), lubricity additive or pill in water based drilling fluids and discharged with those drilling fluids provided the discharge continues to meet the "No free oil" and 96-hour LC50 toxicity limits (see below for description), and a pill is removed prior to discharge. (2) The discharge of oil-based drilling fluids and oil-based inverse emulsion drilling fluids are prohibited. (3) Drilling fluids to which any diesel oil has been added as a lubricant may not be discharged. (4) There shall be no discharge of drilling fluids to which barite has been added, if such barite contains mercury in excess of 1.0 mg/kg (dry weight) or cadmium in excess of 3.0 mg/kg (dry weight). (5) No free oil shall be discharged as measured using the static sheen test method. (6) All facilities are subject to a maximum discharge rate of 1,000 barrels per hour.

   Toxicity testing: Operators wanting to discharge drilling fluids must conduct testing to insure the effluent is not toxic to marine organisms. Discharges must meet both a daily minimum and a monthly average minimum 96-hour lethal concentration test (LC50) in which 50% of the test organisms, *Mysidopsis bahia,* must survive the effluent medium. The effluent medium must be at least 30,000 ppm in a 9:1 seawater to drilling fluid suspended particulate phase (SPP) volumetric ratio. Monitoring shall be performed at least once per month for both a daily minimum and the monthly average. In addition, an end-of-well sample is required for a daily minimum when drilling is conducted using aqueous-based drilling fluid. The type of sample required is a grab sample, taken from beneath the shale

shaker, or if there are no returns across the shale shaker, the sample must be taken from a location that is characteristic of the overall mud system to be discharged. Permittees shall report the results on the DMR using either the full toxicity test or the partial toxicity test as specified at 58 FR 12512, March 4, 1993; however, if the partial toxicity test shows a failure, all testing of future samples from that well shall be conducted using the full toxicity test method to determine the 96-hour LC50.

Monitoring: Toxicity monitoring shall be performed at least once per month for both a daily minimum and the monthly average. Monitoring for sheen shall be performed using the static sheen method once per week when discharging. The permittee shall also maintain a precise chemical inventory of all constituents and their total volume or mass added down-hole for each well.

2. **Drill cuttings** – particles of crushed rock produced by the grinding action of the drill bit as it penetrates the earth (Neff 2005). Drill cuttings are suspended in drilling fluids and conveyed up the annulus to the surface where they are removed from the fluid and disposed.

   Restrictions: No free oil as measured using the static sheen test method. Cuttings from oil contaminated drilling fluids are prohibited, including those containing diesel oil or mineral oil. Drill cuttings generated using drilling fluids to which barite has been added shall not be discharged if the barite contains mercury in excess of 1.0 milligram per kilogram (mg/kg) dry weight or cadmium in excess of 3.0 mg/kg dry weight.

   Toxicity: Drill cuttings generated using drilling fluids that do not pass the 96-hour LC50 test described above shall not be discharged.

   Sheen Monitoring: Monitoring shall be performed using the static sheen test method once per week when discharging. Monitoring of base fluids retained on cuttings shall be performed at least once per day when generating new cuttings, unless meeting the conditions of a best management practice as described in the permits.

3. **Produced water** – The water (brine) brought up from the hydrocarbon-bearing strata during the extraction of oil or gas. This can include formation water, injection water, and any chemicals added down-hole or during the oil/water separation. Since the oil/water separation process does not completely separate the oil, some hydrocarbons remain with the produced water and often the water is treated to prevent the formation of sheen. The composition of the discharge can vary greatly in the amounts of organic and inorganic compounds and may include: aluminum, arsenic, barium, benzene, cadmium, chromium, copper, cyanide, lead, mercury, nickel, selenium, silver, and zinc among others. The EPA general permits allow the discharge of produced waters provided they meet discharge criteria. Discharge volumes are variable and may range from 500-2,500 barrels per day.

Restrictions: Discharged oil and grease cannot exceed 42 milligrams per liter (mg/l) daily maximum or 29 mg/l monthly average (technology-based limits). The discharge must also be tested for toxicity on a monthly basis.

Toxicity testing: Platforms wishing to discharge produced waters will be required to test the effluent for toxicity. Test results are good for a period of 6 months.

7-day chronic toxicity testing – Tests the survival and growth of mysid shrimp *(Mysidopsis bahia)* and larval inland silversides *(Menidia beryllina)* in a series of effluent dilutions (different dilutions based on a critical dilution as determined by flow rates and the depth of discharge for each platform) in comparison to a control group. The purpose of the test is to determine the greatest effluent dilution at which no significant effect is observed between the test and the control (no observable effects concentration - NOEC). The 7-day average minimum and monthly average minimum NOEC must be equal to or greater than the critical dilution concentration. Test is to be completed at least every 6 months.

Sheen Monitoring: Monitoring shall be performed using the static sheen test method once per day when discharging when a facility is manned. Grab sampling for oil and grease analysis will be conducted once per month. Flow rates shall also be monitored once per month.

4. **Well treatment, completion fluids, and workover fluids**
    a. Well treatment fluids are any fluids used to restore or improve productivity by chemically or physically altering hydrocarbon-bearing strata after a well has been drilled. These fluids are typically added down-hole and mostly remain within the wellbore; any fractions that may escape are subject to the limitations described in the following restrictions.
    b. Completion fluids are salt solutions, weighted brines, polymers, and various additives used to prevent damage to the well bore during operations which prepare the drilled well for hydrocarbon production.
    c. Workover fluids are salt solutions, weighted brines, polymers, or other specialty additives used in a producing well to allow for maintenance, repair, or abandonment procedures. This includes packer fluids.

    Restrictions: No free oil as measured using the static sheen test method and no priority pollutants except in trace amounts (as established in the 2005 issued permit) may be discharged. Fluids must also meet both a daily maximum of 42 mg/l and a monthly average of 29 mg/l limitation for oil and grease.

    Sheen Monitoring: Sampling for the static sheen test will be done daily when a discharge occurs. Grab sampling for oil and grease analysis will be conducted once per month and should not exceed technology-based limits.

5. **Deck drainage** – Any waste resulting from deck washings, spillage, rainwater, and runoff from gutters and drains including drip pans and work areas within facilities subject to this permit. Deck drainage of the largest concern include oil and detergents, drilling fluids, and acids used during workover operations.

Restrictions: No free oil shall be discharged as determined by the presence of a film or sheen upon the surface of the receiving water. Typically these platforms are equipped with pans to collect deck drainage. The drainage is separated by gravity into waste material and liquid effluent. Waste materials are sent to a sump tank for treatment followed by disposal, recycling back to the drilling mud system, or transport to shore. Liquid effluent is discharged to the sea.

Monitoring: Visual sheen test method to be completed once per day when discharging.

6. **Sanitary waste** – human body waste discharged from toilets and urinals located within facilities subject to this permit. The volume and concentrations of these wastes vary widely with time, occupancy, platform characteristics, and operational situation. Past monthly average sanitary waste flows from Gulf Coast platforms was approximately 35 gallons per day (EPA 1993).

   Restrictions: No floating solids and residual chlorine to be maintained as close to 1 mg/l as possible for facilities continuously manned by 10 or more persons. No floating solids for facilities continuously manned by 9 or fewer persons. Any facility that properly operates and maintains a marine sanitation device (MSD) that complies with pollution control standards and regulations under Section 312 of the Clean Water Act shall be deemed to be in compliance with permit limitations for sanitary waste.

   Monitoring: Observation for floating solids shall be conducted once daily during discharge while sampling for residual chlorine shall be done once per month. If a MSD is being used, yearly testing to insure proper operation is required.

7. **Domestic waste** – Material discharged from galleys, sinks, showers, safety showers, eye wash stations, hand washing stations, fish cleaning stations, and laundries. The volume of domestic waste discharged is estimated to be 50-100 gallons per person per day.

   Restrictions: No floating solids or foam and require compliance with the requirements of 33 CFR 151. *Region 4 only*: Any soaps and detergents must be phosphate free (contain less than 0.5% phosphate).

   Monitoring: Observation for floating solids shall be conducted daily during daylight hours by visual observation of the receiving waters in the vicinity of the outfall. Observations shall be made following either the morning or midday meals at a time of maximum estimated discharge.

8. **Miscellaneous discharges** – Various discharges of relatively small, though highly variable quantities.

   a. Hydrate control fluids – used to dehydrate natural gas in deep water operations to prevent pipeline blockages. It is unlikely that these fluids will be necessary in the relatively shallow water wells of the territorial seas of Texas. If used, however, they will typically be discharged in the produced water stream and would be limited by the same restrictions.

   b. Blowout preventer control fluid – fluid used to actuate the hydraulic equipment on the blow-out preventer or subsea production wellhead assembly. These may be

discharged periodically in small quantities (67-314 barrels per day, EPA 1993) at the sea floor.

c. Boiler blowdown – discharges from boilers necessary to minimize solids build-up in the boilers, including vents from boilers and other heating systems. Based on past operations, these may be discharged at a volume of 0-5 barrels per day (EPA 1993).
d. Diatomaceous earth filter media – filter media used to filter seawater or other authorized completion fluids and subsequently washed from the filter.
e. Excess cement slurry – the excess mixed cement, including additives and wastes from equipment wash-down, after a cementing operation.
f. Mud, cuttings, and cement at the sea floor – discharges that occur at the sea floor prior to installation of the marine riser and during marine riser disconnect, well abandonment, and plugging operations.
g. Source water and sand – water from non-hydrocarbon bearing formations for the purpose of pressure maintenance or secondary recovery.
h. Uncontaminated or treated ballast/bilge water – seawater added or removed to maintain proper draft or water from a variety of sources that accumulates in the lowest part of the vessel/facility. Volumes may be expected to range from 70-620 barrels per day (EPA 1993).
i. Uncontaminated freshwater or seawater – waters discharged without contact with or addition of chemicals, oil, or other wastes.

Restrictions: No free oil, floating solids, or foam shall be discharged.
Monitoring: Observations shall be made once per week.

9. **Chemically-treated seawater and freshwater** – waters to which corrosion inhibitors, scale inhibitors, biocides, and/or other chemicals have been added and include the following discharges:

    a. Excess seawater which allows the continuous operation of fire control and utility lift pumps
    b. Excess seawater from pressure maintenance and secondary recovery projects
    c. Water released during training and testing of personnel in fire protection
    d. Seawater used to pressure test piping and pipelines
    e. Ballast water or bilge water
    f. Non-contact cooling water
    g. Desalinization unit discharge – the residual high-concentration brine discharged offshore from distillation or reverse osmosis units used for producing potable water. Past operations have discharged this at a volume of up to 238 barrels per day (EPA 1993).

    Restrictions: No free oil and the most stringent of the 3 following conditions:

        i. The maximum concentrations and any other condition specified in the EPA product registration labeling if the chemical additive is an EPA-registered product

ii. The maximum manufacturer's recommended concentration when one exists
iii. 500mg/l

Toxicity testing: 48-hr acute toxicity test will determine if an appropriately dilute effluent sample adversely affects the survival of mysid shrimp and inland silversides. The 48-hr minimum and monthly average minimum NOEC must be equal to or greater than the critical dilution concentration (determined by the discharge rate and the pipe diameter at each facility).

Monitoring: Visual sheen test shall be conducted once per week when discharging. Monitoring for toxicity will be required at least once per 6 months when discharging.

Requirements pertaining to cooling water intake structure regulations per 40 CFR Part 125 Subpart N (Requirements Applicable to Cooling Water Intake Structures for New Offshore Oil and Gas Extraction Facilities under Section 316(b) of the Clean Water Act). These requirements will limit intake velocity, minimize impingement and entrainment, and set monitoring and record keeping requirements (40 CFR 125.134 (b)(2-8)).

In addition, the new permit will also include the following improvement:
Increased ambient water monitoring requirements are replaced with well treatment fluids study.

Appendix F. BOEM Oil and Gas Program AIS vessel types

id	Level 5 type	Level 5 description
1	Aggregates Carrier	A single deck cargo vessel for the carriage of aggregates in bulk. Also known as a Sand Carrier. May be self discharging
2	Waste Disposal Vessel	A vessel equipped for the transportation, treatment and/or (now illegal) discharge at sea of waste material
3	Crane Vessel	A vessel equipped with a large crane for lifting operations
5	Mooring Vessel	A vessel equipped to assist with the mooring and/or anchoring of larger vessels. Typically it will have a frame to prevent the ropes and chains fouling on the superstructure
10	Crude/Oil Products Tanker	A tanker for the bulk carriage of crude oil but also for carriage of refined oil products
11	Shuttle Tanker	A tanker for the bulk carriage of crude oil specifically for operation between offshore terminals and refineries. Is typically fitted with bow loading facilities
12	Pipe Burying Vessel	A vessel equipped to carry small stones and aggregates and to deliver them via a flexible fall pipe system to bury pipes and cables on the sea bed
15	Trailing Suction Hopper Dredger	A vessel equipped to obtain material from the sea bed by use of a trailing suction pipe. The material may be carried on board and discharged elsewhere through the bottom of the vessel, either by bottom doors or a split hull, or delivered to other vessels
16	Supply Platform, semi submersible	A semi submersible offshore supply platform
17	Water Tank Barge, non propelled	A non propelled tank barge for the carriage of water
19	Asphalt/Bitumen Tanker	A tanker for the bulk carriage of asphalt/bitumen at temperatures between 150 and 200 deg C
24	Cable Repair Ship	A vessel equipped for the retrieval and repair of underwater cables
25	Pipe Layer Crane Vessel	A pipe layer also equipped with a large crane or derrick

26	Bulk Cement Barge, non propelled	A non propelled barge for the carriage of bulk cement
33	FSO, Oil	A tanker purpose built or converted to store oil produced from a field prior to its transfer to another vessel for transportation. May be self or non propelled. This type does not include vessels which are temporarily being used for storage of oil
34	Jacket Launching Pontoon, semi submersible	A semi submersible pontoon designed for positioning and launching jackets for offshore use
37	Drilling Rig, jack up	A jack up offshore drilling rig
44	Combination Gas Tanker (LNG/LPG)	A tanker for the bulk carriage of Liquefied Natural Gas (primarily methane) and/or Liquefied Petroleum Gas in independent insulated tanks
52	Research Survey Vessel	A vessel equipped for research and/or survey (e.g. geophysical, hydrographic)
53	LNG Tanker	A tanker for the bulk carriage of Liquefied Natural Gas (primarily methane) in independent insulated tanks. Liquefaction is achieved at temperatures down to -163 deg C
54	Effluent carrier	A vessel equipped for the transportation of effluents. Discharge at sea is now illegal
55	Utility Vessel	A small multi functional response vessel not dedicated to a particular function
57	Anchor Handling Tug Supply	An offshore tug/supply ship equipped with a high bollard pull and a stern roller for anchor handling
58	Accommodation Platform, semi submersible	A semi submersible offshore accommodation platform
71	Cement Storage Barge, non propelled	A barge with pumping facilities for loading & discharging cement.
82	Support Platform, jack up	A non-propelled jack up vessel for offshore support
83	Pollution Control Vessel	A vessel equipped for the primary function of pollution control. Typical types include oil spill recovery vessel and a pollution and debris collector
86	Pusher Tug	A vessel equipped to push cargo-carrying barges and pontoons.
88	Bulk/Oil Carrier (OBO)	A bulk carrier arranged for the alternative (but not simultaneous) carriage of crude oil
91	Crane Platform, jack up	A jack up offshore crane platform
94	Crane Vessel, non propelled	A non self propelled vessel equipped with a large crane for lifting operations

96	Bulk Aggregates Barge, non propelled	A non propelled barge for the carriage of bulk aggregates
99	Jacket Launching Pontoon	A pontoon designed for positioning and launching jackets for offshore use
100	Crew Boat	A vessel equipped for the transportation of crew to ships and/or installations
102	Crude Oil Tanker	A tanker for the bulk carriage of crude oil
107	Hopper/Dredger (unspecified)	A vessel equipped to obtain material from the sea bed by an unspecified means. The material may be carried on board and discharged elsewhere through the bottom of the vessel, either by bottom doors or a split hull, or delivered to other vessels, pumped a
110	FSO, Gas	A tanker purpose built or converted to store gas produced from a field prior to its transfer to another vessel for transportation. May be self or non propelled. This type does not include vessels which are temporarily being used for storage of gas
112	Barge Carrier	A cargo vessel arranged for the carriage of purpose built barges (lighters) loaded with cargo. Typically loading is by way of a gantry crane. Also known as Lighter Aboard SHip vessels (LASH)
113	Grab Dredger	A vessel equipped to obtain material from the sea bed by use of a grab. The material may be carried on board, transferred to other vessels, pumped ashore or deposited elsewhere using a spray
118	Pipe Carrier	A platform supply ship equipped with increased scantlings & longer deck space for the transportation of pipes
123	Pipe layer Platform, semi submersible	A semi submersible offshore pipe layer platform
131	LPG Tanker	A tanker for the bulk carriage of Liquefied Petroleum Gas in insulated tanks, which may be independent or integral. The cargo is pressurised (smaller vessels), refrigerated (larger vessels) or both ('semi-pressurised') to achieve liquefaction.
132	Well Stimulation Vessel	A vessel primarily equipped to maximize oil production from a well
136	Grab Hopper Dredger	A vessel equipped to obtain material from the sea bed by use of a grab or backhoe. The material may be carried on board and discharged elsewhere through the bottom of the vessel, either by bottom doors or a split hull, or delivered to other vessels, pump

147	Ore/Oil Carrier	An ore carrier arranged for the alternative (but not simultaneous) carriage of crude oil
152	Maintenance Platform, semi Submersible	A semi submersible offshore maintenance platform
153	Tug	A vessel equipped with a towing winch to tow other vessels (either in harbour or in open sea) and with manoeuvring capabilities to assist vessels to berth/unberth in ports. May also be able to push barges and other vessels
155	Pipe Layer	A vessel primarily equipped to lay solid or flexible pipes on the sea bed
156	Pile Driving Vessel	A vessel equipped for pile driving operations
158	FPSO, Oil	A vessel with the capability to control production rates from an oilfield and to store oil produced prior to its transfer to another vessel for transportation. May be self or non propelled
162	Production Platform, jack up	A jack up offshore production platform
165	Offshore Tug/Supply Ship	A vessel for the transportation of stores and goods to offshore platforms on an open stern deck and equipped with a towing facility
166	CNG Tanker	A tanker for the bulk carriage of Compressed Natural Gas. Cargo remains in gaseous state but is highly compressed
167	Offshore Support Vessel	A single or multi functional offshore support vessel
168	Accommodation Platform, jack up	A jack up offshore accommodation platform
175	Water Tanker	A tanker for the bulk carriage of water
176	Trenching Support Vessel	A vessel primarily equipped to operate submersibles for digging trenches on the sea bed for pipes and cables
177	Crude Oil Tank Barge, non propelled	A non propelled tank barge for the carriage of crude oil
180	Cable Layer	A vessel equipped to lay and repair underwater cables
182	Sheerlegs Pontoon	A pontoon with sheerlegs for lifting
184	Production Platform, semi submersible	A semi submersible offshore production Platform
186	Drilling Ship	A vessel primarily equipped for offshore drilling operations. May also be able to obtain cores for research purposes
187	Anchor Handling Vessel	A vessel equipped to assist with the handling of anchors

188	Barge Carrier, semi submersible	A barge carrier which is semi submersible for the float on loading/unloading of the barges
194	Heavy Load Carrier, semi submersible	A heavy load carrier which is semi submersible for the float on loading/unloading of the cargoes
195	LPG/Chemical Tanker	An LPG tanker additionally capable of the carriage of chemical products as defined in the International Bulk Chemical Code
210	Drilling Rig, semi submersible	A semi submersible offshore drilling rig
214	Suction Dredger Pontoon	A non propelled dredger pontoon fitted with suction equipment
218	Passenger Ship	A vessel certificated to carry more than 12 passengers, some of whom may be accommodated in cabins
222	Crew/Supply Vessel	A typically high speed vessel primarily for the transportation of crew to offshore facilities; may also have limited stores carriage capability on an open deck
228	Work/Repair Vessel	A multi functional vessel for general work and repair operations
236	Floating Dock	A submersible unit constructed and fitted out to dry dock ships whilst afloat.
237	Cement Carrier	A single deck cargo vessel fitted with pumping arrangements for the carriage of cement in bulk. There are no weather deck hatches. May be self discharging
238	Salvage Ship	A vessel equipped for salvage operations
239	Diving Support Platform, semi submersible	A semi submersible diving support platform
243	Crane Platform, semi submersible	A semi submersible offshore crane platform
244	Deck Cargo Pontoon, semi submersible	A non propelled semi submersible pontoon for the carriage of general deck cargoes
248	LPG Tank Barge, non propelled	A non propelled tank barge for the carriage of LPG
251	Suction Hopper Dredger	A vessel equipped to obtain material from the sea bed by use of a suction pipe. The material may be carried on board and discharged elsewhere through the bottom of the vessel, either by bottom doors or a split hull, or delivered to other vessels
256	Supply Platform, jack up	A supply platform, jack up
258	Accommodation Ship	A vessel providing accommodation for those working on other vessels and installations

263	Standby Safety Vessel	A vessel primarily equipped to perform safety standby duties. Will be fitted with accommodation and facilities for the rescue, reception and initial care of survivors from offshore installations accidents
271	Pipe layer Platform, jack up	A jack up offshore pipe layer platform
277	Diving Support Vessel	A vessel primarily equipped with decompression chambers for air dive operation. Does not include vessels which can only operate submersibles
281	Platform Supply Ship	A vessel for the transportation of stores and goods to offshore platforms on an open deck, typically at the stern. May also be fitted with specialist under deck tanks for water, cement and/or drilling mud
286	Cutter Suction Dredger	A vessel equipped to obtain material from the sea bed by use of a cutter wheel, which loosens the material, and a suction pipe. The material may be carried on board, transferred to other vessels, pumped ashore or deposited elsewhere using a spray
297	Production Testing Vessel	A vessel primarily equipped for testing the quality and amount of oil produced by a well
298	Mechanical Lift Dock	A lifting dock facility using winches to lower and raise platform
301	Offshore Construction Vessel, jack up	A propelled vessel with a self-elevating facility to facilitate offshore maintenance, construction and/or installation
305	Grab Dredger Pontoon	A non propelled dredger pontoon fitted with a system of grabs
318	Suction Dredger	A vessel equipped to obtain material from the sea bed by use of a suction pipe. The material may be carried on board, transferred to other vessels, pumped ashore or deposited elsewhere using a spray

Appendix G. Extremely large spill assessment

Before we conducted our hazard assessment and exposure analysis for oil spills associated with the proposed action, we first assessed the available information used to determine the potential largest spill size volumes (refer to Table 114 in the Opinion), which one of these estimates of representative very large spill sizes was provided by BOEM (100,000 bbl per Ji et al. 2014).

Determination of the Upper Range of Spill Sizes

BOEM has defined very large spills as any spill volume greater than or equal to 10,000 bbl, and provided NMFS with information projecting that two oil spills greater than or equal to 10,000 bbl may occur over the duration of the proposed action. However, BOEM has not defined an upper volume for such a spill size. BOEM stated that it "does not consider an extremely large event as reasonably certain to occur" over the time frame of this opinion, although BOEM does acknowledge that impacts from the DWH blowout and resulting spill warrant inclusion in Gulf of Mexico consultation as part of the environmental baseline. For informational purposes for decision-makers, BOEM used current reservoir sizes to demonstrate the size and duration of extremely large releases in shallow water and deepwater areas. BOEM characterized an extremely large spill in shallow water as being uncontrolled flow for one to three months, resulting in an estimated range of 900,000-3,000,000 bbl released[1]. For deep water, BOEM provided information that if an extremely large event occurred and remained uncontrolled up to four months, potentially 2.7-7.2 million bbl could be released. Following our analysis of spill data and statistical assessments of the occurrence of very large spills that is explained in more detail below, we estimated the volume of the largest spill size based on the duration of a spill that could possibly occur over the timeframe of the opinion.

A fundamental challenge is to accurately describe this risk, especially since there have been relatively few large to very large oil spills that can serve as benchmarks. Prior to the DWH event, the three largest blowout spills on the U.S. OCS were 80,000 bbl, 65,000 bbl, and 53,000 bbl, and all occurred before 1971 (Anderson et al. 2012). At the present time, there is a not an ideal, standardized approach to characterizing the risk of spill occurrence and consequence. Historically, BOEM has characterized oil-spill risk using the Oil Spill Risk Analysis (OSRA) model to identify the risk of oil released from numerous locations on the OCS occurring and contacting environmental, social and economic resources. BOEM performs OSRA modeling in the evaluation of individual lease sales and certain exploration/development plans. BOEM or BSEE also consider risk during the review of an operator's Exploration Plan, Development and Production Plan (or Development Operations Coordination Document), and/or Application for Permit to Drill.

BOEM's probabilistic spill estimates use an oil spill risk method based on historical spill rates per volume of oil produced. The number of spills has been estimated for different spill sizes based on the anticipated volume of oil produced over this consultation period. One data point,

[1] BOEM 2014 Qualitative Review of Safety Measures to Minimize Frequency of Blowouts and Spills and Maximize Containment Capabilities

the DWH event, represents both the greater than or equal to 10,000 bbl and extremely large spill categories in BOEM's analyses. The lack of data for very large spills results in a high degree of statistical uncertainty. It is worth noting that BOEM's methodology would not have predicted that the DWH event would have occurred. Because of this high uncertainty to produce probabilistic estimates of the frequency of large oil spills resulting from protracted loss of well control, BOEM provided NMFS additional information to support their conclusions. BOEM provided NMFS a summary of recent peer reviewed literature regarding oil spills, information on new safety requirements, spill response preparedness, and new spill response and containment technology. Given the additional information we decided to defer to BOEM as the experts on the probability of occurrence of an extremely large spill.

To estimate a reasonable maximum possible spill size, we considered the following main factors:

- The pre-DWH spill risk considered in the 2007 biological opinion.
- The causes of blowout, loss of well control and other potential risks that cause spills.
- Information from our review of extremely large spill risk assessments provided by BOEM, federal reports, and independent studies on determining the risk and frequency of very large spills found in the peer-reviewed literature.
- Regulatory reforms and improvements in offshore drilling safety since DWH. Assuming some risk of a blowout and other risk factors, we will consider the likelihood of those risk factors that could actually result in a loss of well control and uncontrolled release of oil into the ocean.
- The volume of oil that could be spilled in the future using BOEM's estimated flow rates.
- The anticipated flow duration of an uncontrolled blowout based on our assessment of the ability of industry to rapidly respond to a blowout and bring a well under permanent control.
- The adequateness of OSRPs to prepare for extremely large spill responses, limit the duration of the spill, clean up the oil, and respond to ESA-listed species and critical habitat that may be affected.

Pre-Deepwater Horizon Risk

In the 2007 biological opinion, although BOEM did not predict a major, uncontrolled oil spill, we predicted that a single extremely large spill would occur approximately every 40 years. That estimate proved reasonably accurate, with the DWH spill's occurrence 31 years after Ixtoc I and is reflected in the 26-34 year pre-DWH extremely large spill frequency estimate found in the economic analysis prepared for BOEM's drilling safety rule (https://www.bsee.gov/sites/bsee.gov/files/research-guidance-manuals-or-best-practices/regulations-and-guidance/aa02-final-rule-8-10-12.pdf). Our 2007 opinion significantly underestimated the severity of a major uncontrolled release, as evidenced by the DWH event. The flow rate of oil from the well and the amount of time it took to bring the well under control were the primary reasons we underestimated the size of and impacts associated with the largest spill we predicted would occur. Our underestimate of impacts to listed species was the primary reason reinitiation of consultation was requested in 2010. During consultation, we emphasized

the necessity of additional information on the risk of future extremely large spills to complete this opinion.

Causes of Very Large Oil Spills and Risks

Blowouts and subsequent losses of well control are the primary concern for a very large release of oil in the Gulf of Mexico. Blowouts are generally associated with equipment failures, human error, hurricane-related failures, or a combination of these events. The DWH event has been the only disastrous blowout and loss of well control on the U.S. OCS in the Gulf of Mexico; therefore, in this section, we will review the past occurrences of blowouts, as well as some recent causes of other large, but non-disasterous oil spills.

There have been 21 blowouts associated with seven individual events that have resulted in loss of well control in the Gulf of Mexico (Table 1). Four of the spills were the result of hurricane-related failures, another four were the result of blowouts during drilling, and the remaining spills resulted from a single event where a platform shifted position and blew out all the wells connected to it. Four of these blowout-related spills, including DWH, were greater than 10,000 bbl. Until the occurrence of the DWH event, all blowout-related spills occurred between 1965 and 1970 (Table 1).

Table 1. Blowouts on the Federal OCS that have Resulted in Loss of Well Control and Oil Spills Greater than 1,000 bbl.

Year of Spill Event	Number of Blowouts	Duration (days)	Water Depth (ft)	Volume Spilled (bbl)	Details
1964	3	several days	48	5,180	Hurricane Hilda destroyed 3 platforms in Eugene Island, Block 208
1964	1	17	33	5,100	Hurricane Hilda destroyed a platform in Ship Shoal, Block 149
1965	1	8	190	1,688	Drilling Blowout in Ship Shoal, Block 29
1969	1	10	190	80,000	Drilling blowout in Santa Barbara Channel in lease area 6B 5165
1970	13	49	39	65,000	Rig shift and fire resulting in 13 blowouts in Main Pass, Block 41

Year of Spill Event	Number of Blowouts	Duration (days)	Water Depth (ft)	Volume Spilled (bbl)	Details
1970	1	138	60	53,000	Drilling blowout and fire in South Timbalier, Block 26
2010	1	86	4,992	4.9 million est.	Blowout and fire in Mississippi Canyon, Block 252

Source: BOEM BA supplemental information

Several other non-blowout-related spills were caused by Hurricane Rita in 2005 (six structures lost or damaged), Hurricane Jeanne in 1980 (one damaged structure), a sinking storage barge (one event), vessels colliding with platform (two events), and leaking storage structures (three events) (Table 2). However, all but one of these non-blowout-related spills were less than 10,000 bbl.

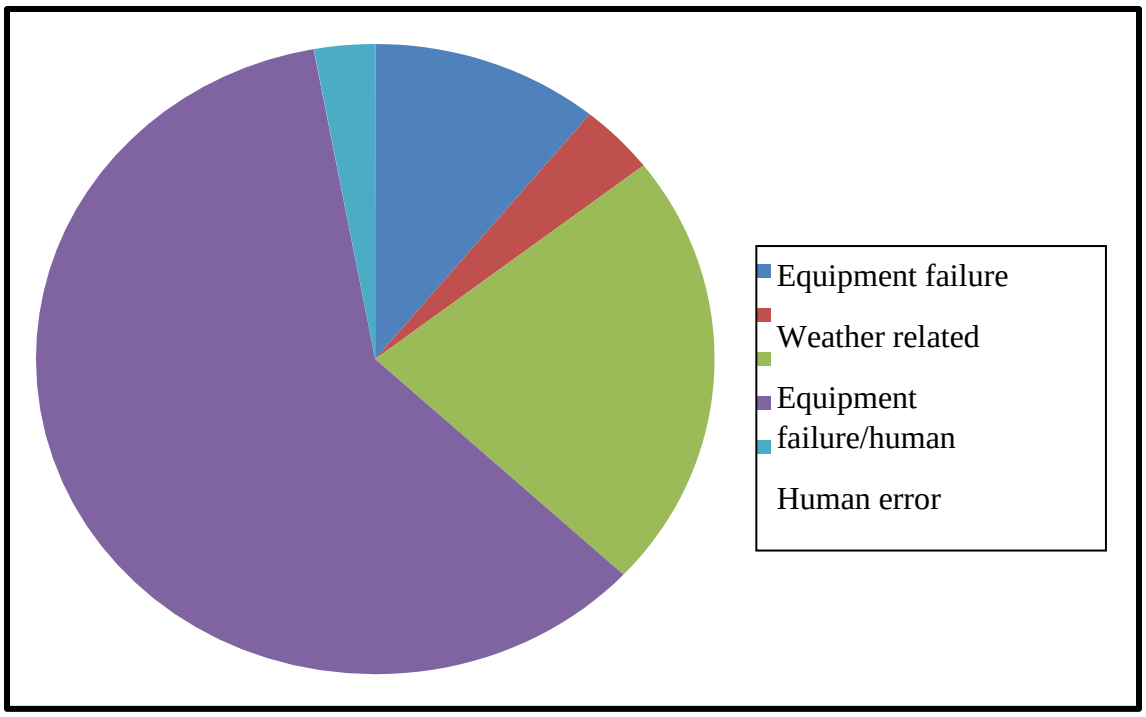
Table 2. Non-blowout Spills on the Outer Continental Shelf that Have Resulted in Spills Greater than 1,000 bbl.

Year of Spill Event	Number of Structures	Water Depth (ft)	Volume Spilled (bbl)	Details
1964	1	94	2,559	Freighter struck platform in Eugene Island, block 208.
1964	1	102	1,589	Storage tank lost during Hurricane Hilda in Ship Shoal, Block 149
1969	1	30	2,500	Supply vessel collided with a semisubmersible drilling rig in Ship Shoal, Block 72
1973	1	110	9,935	Storage tank failure in West Delta, Block 79
1973	1	61	7,000	Storage barge sank
1979	1	61	1,500	Workboat collided with a drilling rig putting a hole in a diesel tank, Main Pass, Block 151

Year of Spill Event	Number of Structures	Water Depth (ft)	Volume Spilled (bbl)	Details
1980	1	60	1,456	A storage tank overflowed during evacuation of platform during hurricane Jeanne, High Island, Block 206
2004	1		>1,000	Hurricane Ivan and underwater landslide toppled platforms and severed numerous wellheads. Low discharge, chronic oil seepage is still ongoing.
2005	3	182-238	5,066	Hurricane Rita destroyed 1 platform and 2 drilling rigs.
2013	1		1,531	Drilling rig lost station; lower marine riser emergency disconnect activated.
2015	1		2,200	Lower marine riser installation error.
2016	1		2,100	Subsea flowline.
2017	1		16,152	Subsea jumper (pipeline segment) damage.

Source: BOEM BA supplemental information

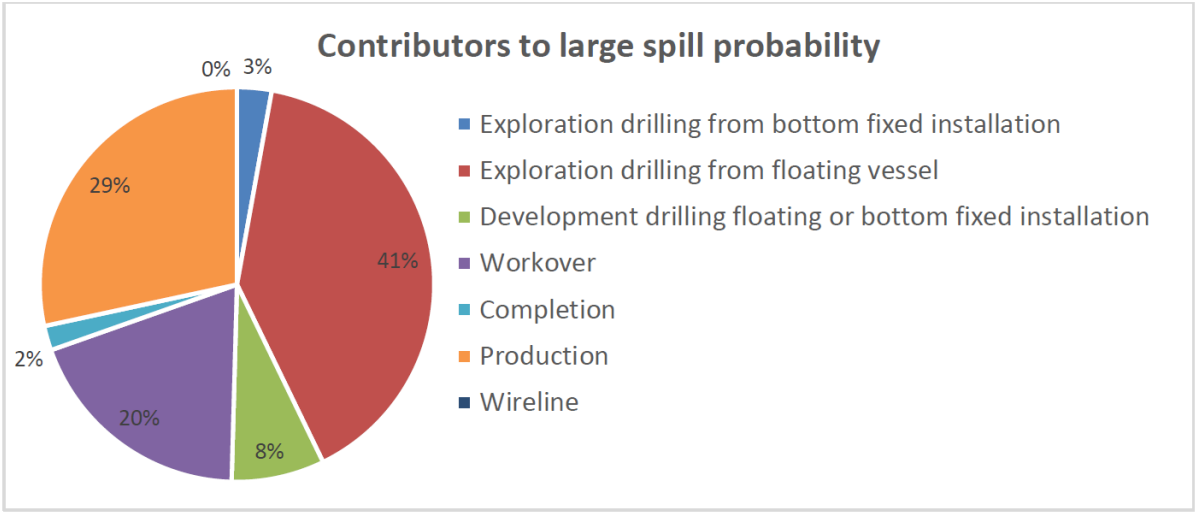
After the DWH incident, from 2011-2013 BSEE investigated 139 total accidents including 18 spill releases. One hundred and fifteen accidents (82.7 percent) were caused, at least in part, by human error and 73 (52.5 percent) were determined to have been entirely caused by human error (Figure 1). Eighteen of the accidents (12.9 percent) resulted in some type of pollution being released and those included spills of less than one gallon of gas/oil (only enough to produce a sheen), minor chemical or diesel spills associated with facility maintenance, drilling fluid releases and releases of synthetic oil based mud. Spills were mainly small volumes of oil caused by human error (misuse of equipment or failure to notice an over-pressurized vessel), sometimes leading to a series of events, and ultimately causing an unplanned release.



Source: BOEM BA supplemental information

Figure 1. Causes of oil and gas accidents reported on the Gulf of Mexico OCS from 2011-2013 as reported to BSEE.

BSEE (2017) examined loss of well control events and categorized contributors to the probability as shown in Figure 2, and Figure 3 displays BSEE's risk analysis for oil spills caused by loss of well control events. The highest risk events are the blowout (surface flow) accidents, which have potential for the more severe overall impacts (BSEE 2017). According to BSEE (2017), risk may be reduced by reducing the drilling kick frequency.



Source: BOEM BA supplemental information

Figure 2. Pie chart from BSEE (2017) displaying the categories of contributors to large spill probability.

Probability	LOWC consequence (Spill size)					
	No or insignificant spill	Minor spill (10 - 50 bbls)	Medium spill (50 -500 bbls)	Large spill (500 – 5,000 bbls)	Very large spill (5,000 - 50,000 bbls)	Gigantic spill (>50,000 bbls)
More frequent than once a year	X					
1 - 5 times in 5 year		X				
1 - 4 times in 20 year						
1- 4 times in 80 year			X			
1 - 2 times in 160 year				X	X	X
less than once in 160 year						

Source: BOEM BA supplemental information

Figure 3. Risk matrix from BSEE (2017) for oil spills caused by loss of well control events, with the X indicating BSEE's predicted loss of well control risk level. Red indicates high risk, yellow indicates moderate risk, green indicates low risk.

Based on our review of the historical spill data above, the cause of spills occurring in volumes greater than 10,000 bbl could likely be the result of a loss of well control resulting from a drilling-related blowout. Three of the four very large drilling-related blowouts that have occurred in the greater than or equal to 10,000 bbl category average a spill size of 66,000 bbl (53,000, 65,000 and 80,000 bbl) and one spill (DWH) has been extremely large (≥ three million bbl). BOEM has indicated that two spills greater than 10,000 bbl may result from the proposed action. Based on the historical data above and the estimate of the number of spills provided by BOEM, two very large (greater than 10,000 bbl) drilling-related releases of oil can be expected to occur during the next 50 years, for the reasons discussed in further detail below. The information above leads us to conclude that one of these spills can be expected as the result of a blowout resulting in a release of 100,000 bbl (per Ji et al. 2014; and Table 114, section 8.8 of the biological opinion). Since we have only a single extremely large release of oil (the DWH event) from which to estimate future impacts, we will next consider in more detail the frequency and likely largest size of such extremely large releases occurring on the OCS.

Best Available Information on the Largest Potential Spill

This section first provides a summary of some relevant peer-reviewed literature regarding statistical methods to predict the risk of extremely large spills occurring from significant uncontrolled blowouts. As discussed above, loss of well control and associated extremely large release of oil is more likely to occur in deep water due to the increased risks associated with higher well pressures and the technological challenges of drilling in deep water than are present in shallow water. Many regulatory changes have been made since the DWH event. NMFS agrees with BOEM that new regulatory and technological advances reduce the risk of another DWH-sized event. However, the effectiveness of the changes cannot be quantitatively measured. By their very nature, oil spill risk analyses rely on data from past accidents to project future spill occurrences. Consequently, analyses published since the DWH event do not consider the effectiveness of post-DWH risk-reducing measures that decrease the likelihood or magnitude of

spills which occur in the future. NMFS requested that BOEM provide a quantitative estimate of risk reduction from their new regulations, but this was not provided. Thus, we consider qualitative information on risk reducing measures that BOEM provided and we will take into account that oil and gas drilling is occurring in increasingly deeper waters thereby increasing risk. An ultra-deep lease at 2200 m can yield a predicted 374.9 thousand barrels per month-18 times a lease at 200m deep (Murawski et al. 2020). Murawski et al. (2020) also states: "The inherent risks of catastrophic well blowouts at extreme depths will increase as the productivity of oil facilities increases exponentially with water depth." The following summarizes some of the relevant oil spill risk literature since DWH.

Muehlenbachs et al. 2013 provides an empirical analysis of company-reported incidents (e.g. blowouts, injuries, spills) on oil and gas production platforms in the Gulf of Mexico between 1996 and 2010. This same time period was marked by a dramatic increase in the depths at which offshore oil and gas extraction occurred. Compared with platforms at water depths less than 1,000 ft, the average number of incidents increases more than threefold for depths greater than 1,000 ft. One of the key findings is that company-reported incidents (such as blowouts, fires, injuries, and pollution) increase with water depth. Controlling for platform characteristics such as age, quantity of oil and gas produced, and number of producing wells, for an average platform, each 100 ft of added depth increases the probability of a company-reported incident by 8.5 percent. The paper does not demonstrate that there is a causal link between water depth and incident or violations, but it demonstrates there are statistically significant relationships between the variables.

Rathnayaka et al. (2013) developed an accident modeling and risk assessment framework based on "early warning" accident precursors using system hazard identification, prediction and prevention methodology to model the event. The risk assessment methodology was demonstrated using the DWH event and modeled over a given time period a disasterous event occurrence probability of 1.52×10^{-5}. Results generated from this method of assessment can provide a comprehensive understanding of safety barrier performance, occurrence probabilities, risk values of severity levels, and safety performance of the deepwater drilling rig.

Xue et al. (2013) proposed a new barrier-based accident model for drilling-related blowouts based on the three-level well-control theory: primary and secondary well-control barriers and an extra well-monitoring barrier established between the reservoir and the blowout event. The DWH event was used as a case study to show how the model can be used to understand the development of events leading to an accident and can also be used as an aid to prevent future blowouts or to stop the escalation of events. In addition to primary and secondary barriers, well monitoring is included as an independent and special barrier between the other barriers. Well monitoring is considered crucial to remedy an incomplete primary well barrier or activate the secondary barrier in a timely manner. The authors state that "the simplest and safest way to prevent blowout accidents is certainly keeping all the safety barriers intact" and further noted that "these failures, especially the ones based on statistical data or accident reports, are still conceptual because the records or reports are not always sufficiently detailed."

In Eckle et al. (2012) accidental global oil spills in the energy sector larger than 200 tons between 1974 and 2010 were extracted from the global Energy-Related Severe Accident Database, resulting in a total of 1,213 accidents. This independent analysis with global data of marine exploration and production oil spills, including the DWH event, calculated an approximate return frequency (i.e., occurrence) of an event the size of DWH as of once every 17 years with an uncertainty of between eight and 91 years (five and 95 percent confidence). The high uncertainty is a direct result of the structure of the risk with few but very severe events. Importantly, given that this analysis relied on a global dataset, the calculated return period represents the occurance on a global scale.

Ji et al. (2014), an analysis conducted by BSEE oil spill experts, used new methods to predict rare events and apply extreme value methods to predict the return period specific to the OCS for extremely large spills. These methods have been used with good results for other events that are rare when considered individually for a smaller area or shorter time period, but become predictable or foreseeable when larger areas and longer times periods are considered. The authors used Federal OCS oil spill data from 1964-2012, which mainly consists of data from the Gulf of Mexico. This study predicted the return period for a worst-case spill (defined as a spill over 1 Mbbl) as 165 years with a 95 percent confidence interval between 41-500 years (Ji et al. 2014).

The peer-reviewed literature discussed above highlights some key points that are relevant for determining the largest spill size that is possible within the time frame covered in the scope of this opinion. The large range of predicted frequency, or return periods, of disasterous spills from a minimum of 17 years globally to more than 500 years in the Gulf of Mexico specifically demonstrates that different statistical methods and different data sets can yield very different results. Human error and hurricanes play a large role in the occurrence of large spill events and occurrence of blowouts resulting in loss of well control in the Gulf of Mexico. There is some evidence suggesting that there may be a relationship between increased accidents as the depth of oil and gas development increases (Muehlenbachs et al. 2013). Increased accident rates could lead to an increased risk of an oil spill occurring.

BOEM estimates that in an average year operators will drill 160 deepwater wells and 186 shallow wells on the federal OCS. In shallow water, well pressures are generally lower due to the fact that many reserves have been produced, resulting in lower well pressures and the general trend of no new large discoveries in shallow water. Although small to medium volumes of oil are sometimes released from blowouts, the blowout is most often controlled with safety equipment such as BOPs, and any release of oil is minimized.

BOEM believes that a blowout leading to a loss of well control and release of oil is most likely in water deeper than 3,000 ft, where the spill size and consequences from a blowout are estimated to be greater (BSEE 2012). Figure 2 displays the annual number of blowouts resulting in a loss of well control from 2007 through 2016. Although blowouts may still occur in shallow water, there is a high likelihood that well control will be maintained due to lower reservoir pressure, the greater prevalence of gas rather than oil, and the presence of more accessible surface BOPs with diverters (BSEE 2012). If a release were to occur, it most likely would not be

a large volume of oil. From 1990-2010, BSEE recorded six Gulf of Mexico shallow water well-control incidents resulting in a spill of hydrocarbons. The total volume spilled is estimated to be 132 bbl of condensate over these last two decades. Our review of the information for shallow water and deep water wells leads us to agree with BOEM's finding of a low risk of an extremely large release of oil in shallow water. However, based on the historical data we analyzed above, including Ji et al. (2014), we believe the very large release of 100,000 bbl of oil could occur either in shallow water or deep water.

Regulatory Reform and Drilling Safety Improvements

BOEM and BSEE have carried out many regulatory reforms in response to reviews of the DWH event to improve offshore safety and oversight. These reforms are expected to reduce the volume of oil spilled during accidental events by reducing risks and improving control and response measures. BOEM provided NMFS a qualitative analysis of oil spill literature, regulatory changes, and improvements in response since DWH. The key points of the 2014 *Qualitative Review of Safety Measures to Minimize Frequency of Blowouts and Spills and Maximize Containment Capabilities* appear in the proposed action section of this opinion. Pertinent to this section of the analysis, we looked at the improvements in the well-containment system and responses that are specifically designed to cap a well after a blowout in order to assess how long a drilling-related extremely large release might last. While the blowout preventer is designed to manage drilling operations and prevent a blowout, a capping stack is designed to be deployed after a subsea blowout has already occurred. At the time of the DWH, there were few capping stacks in existence, and capabilities to support subsea well containment were limited. Subsequent improvements have increased industry's capacity to respond to a subsea well blowout in the Gulf of Mexico. The new well-containment response capability includes multiple vessels for assessment of the well, clearance of debris from the well, and launch and installation of the capping stack. BSEE conducted field testing with installation and testing of capping stacks for Shell and the Marine Well Containment Corporation in July 2012 and Noble Energy and Helix Well Containment Group in April 2013 to assess compliance with their regulations for oil-spill-response/containment systems. In both of these actual field tests, the capping stacks were installed and tested in less than seven days. The total process would take about 21 days under ideal sea conditions. BOEM has indicated that a new capping system has the capacity to contain about 55,000 bbl for transfer to storage vessels and includes a 15,000 psi single or dual ram capping stack. New regulatory measures and improvements in the capping stack technology are effective to bringing a spill under control in shorter time periods than occurred for DWH.

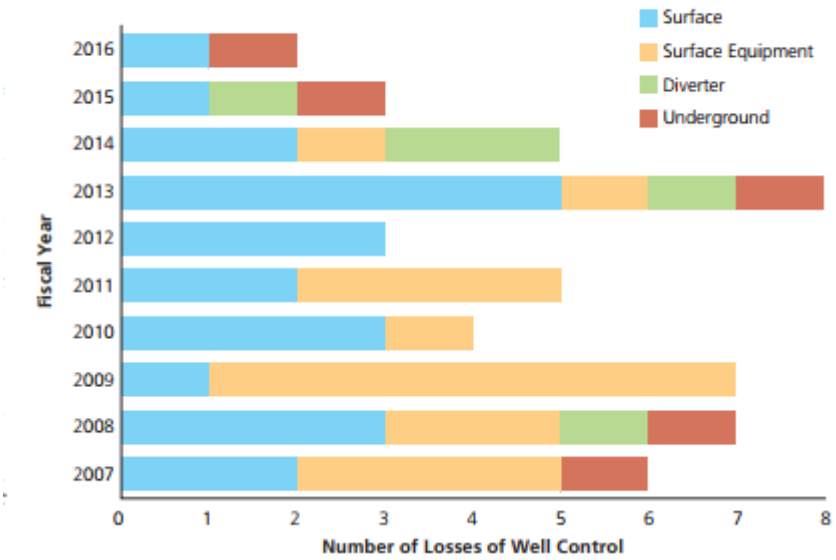


Figure 4. Annual losses of well control from 2007 to 2016 (BSEE 2016).

There were 4,123 deepwater wells drilled between 1973 and 2010. Active leases and associated oil and gas activities have been moving into increasingly deeper waters over the last two decades and are continuing to move into ultra deepwater. As drilling occurs at deeper depths, there can be an increased risk of loss of well control (Murawski et al. 2020). Pressures and temperatures in deeper waters provide extreme conditions where equipment, including safety-critical systems, could be more likely to fail and that are more difficult to reach quickly. Capping deepwater wells is not a regularly-occurring activity, so lack of experience also plays into the risk. Vessels are having to travel much farther to get out to those deeper sites, which could increase spill response times or have fewer available response vessels. Murawski et al. (2020) states, "…the next deep oil blowout and ensuing spill, wherever it may happen, will likely occur under fundamentally different conditions than have the two previous sub-surface mega-blowouts (DWH and Ixtoc)… While the previous 80+ years of oil exploration and production from the Gulf of Mexico have included responses to literally hundreds of oil spills (Ramseur 2010), a 3000 m blowout will be unlike any previous."

Muehlenbachs et al. (2013) reported that the probability of offshore oil and gas accidents increase by 8.5 percent for every 100 feet of increasing depth. BOEM indicated there have been 20 deepwater blowouts. In their 2016 annual report, BSEE calculated an average of five losses of well control per year over the last ten years. According to BSEE's loss of well control data (available at BSEE's website; www.bsee.gov), from 2006 to 2014 and including DWH, there have been eleven blowouts resulting in loss of well control in greater than 2,000 feet of water, eight of which were greater than 3,000 feet of water, and two of which resulted in spills. Since 1990, the frequency of deepwater blowouts is about one blowout for about every 275 deepwater wells. BOEM forecasts that an average of 160 wells will be drilled each year in deep water, or up

to 8,000 wells over the scope of this opinion. Using these estimates, we predict up to 29 blowouts [(1/275)*8000] will occur in deepwater over the next 50 years. Using BSEE loss of well control data to estimate for two spills for every eight loss of well control incidents, we would expect about eight (rounding up) of those blowouts occurring in depths at the greatest risk (i.e., depth greater than 3,000 ft) of an oil spill resulting from loss of well control (Table 3). Eight blowouts in deepwater over 50 years is equivalent to about one deepwater blowout every six years for the proposed action. Based on historical data provided by BOEM, most of these blowouts will result in non-disasterous loss of well control.

Table 3. Deepwater Wells Drilled Greater Than 3,000 ft and Blowout Risk as a Result of the Proposed Action.

Total Wells			
Annual Average Number of Deepwater Wells Drilled	Total Number of Deepwater Wells Drilled under the Proposed Action	Number of Deepwater Blowouts and Subsequent Oil Spill Predicted*	Number of Deepwater Disasterous Blowouts resulting in uncontrolled release of oil
160	8,000	8	1

*Number of drilled deepwater wells resulting in blowout over 38 years.

BOEM has concluded that an extremely large blowout and uncontrolled release of oil should not be considered an effect of the action because the probability is so low that it is not reasonably certain to occur within the time period covered by this opinion and so is not an anticipated result of the proposed action. The more recent analysis by Ji et al. (2014) used more applicable statistical methods to evaluate the risk of extremely large spill events on the U.S. OCS. As noted earlier, this study predicted the return period for a worst-case spill (defined as a spill over 1 Mbbl) as 165 years with a 95 percent confidence interval between 41-500 years. This still results in a wide range of years over which a disasterous uncontrolled blowout might occur. This wide range of years is due, in part, to the high uncertainty involved in predicting rare events. The lower end of this range (the year 2051 is 41 years after DWH) places us at the higher end of the scope of this consultation (2068). According to this statistical prediction, a disasterous blowout, subsequent protracted loss of well control and resulting oil spill would still be a statistically rare event, but it could possibly occur within the timeframe analyzed in this opinion. The majority of spills are less than one barrel, however the majority of volume spilled comes from larger spill events. DWH was 8.5 times the cumulative 570,000 bbl that were spilled in the previous 46 years in the U.S. (Ji et al. 2014). Figure 3, from Ji et al. (2014) shows the time series of annual largest oil spills derived from OCS data for 49 years from 1964 to 2012. The return level (or return frequency or value) of a random variable is the quantile value which is exceeded, on

average, once in a period of time (called the return period). For example, the return period (such as 100-year flood) based on extreme precipitation (i.e., certain return value) is commonly used to assess the capacity of drainage systems (Ji et al. 2014).

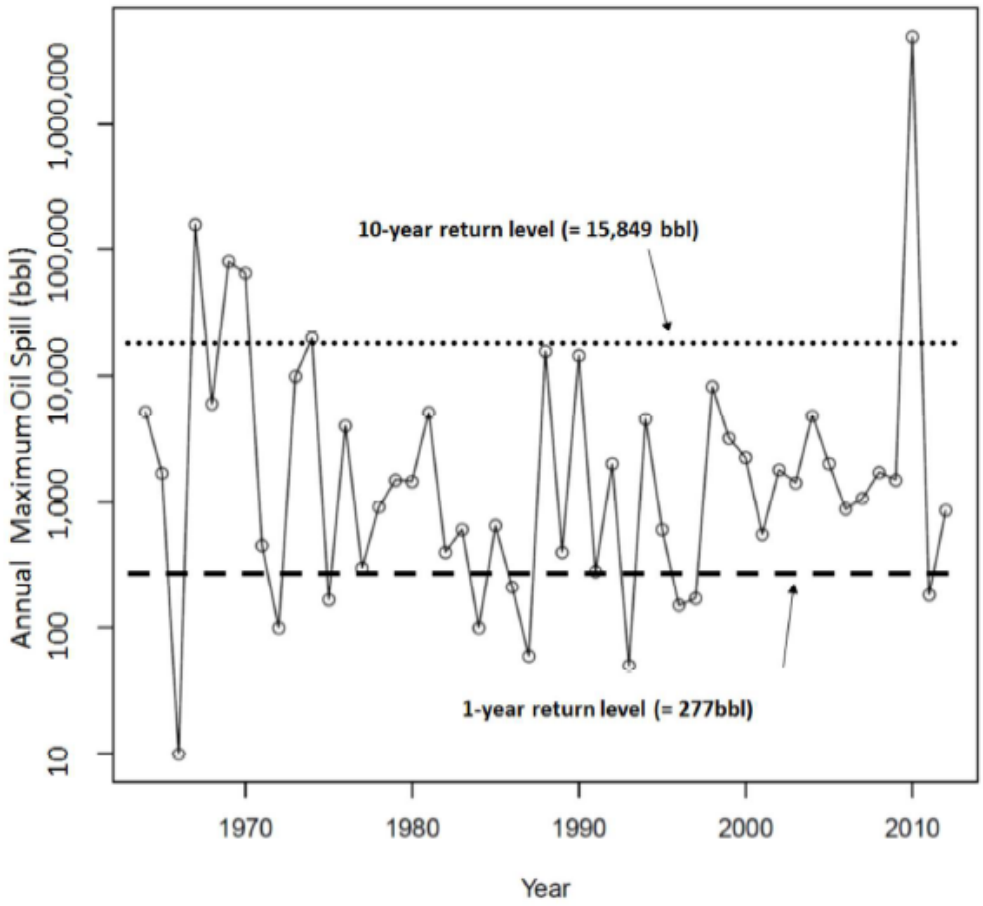


Figure 5. Annual largest oil spills derived from OCS data from 1964 to 2012. The dotted line is the 10-year return level and the dashed line is the 1-year return level. Figure from Ji et al. (2014).

The ranges in return frequencies of oil spills from protracted loss of well control provided in several studies and their strengths/limitations are provided in Table 4. The lower spill return value of 41 years from Ji et al. (2014) is within range of other estimates of possible spill

frequencies[2], and is still consistent with the predicted frequency of one extremely large spill every 40 years used in the 2007 biological opinion. Considering all the information above, while an extremely large spill is hypothetically possible, NMFS agrees with BOEM that new regulatory and technological advances reduce the risk of another DWH-sized event.

Table 4. Comparison from Different Studies of Recurrence Values for Very Large Spill Risk.

Study	Recurrence frequency (years)	95 percent confidence interval (years)	Limitations	Strengths
Rathnayaka et al. 2013	probability 1.52 X 10^{-5}	NA	Narrow focus on DWH and risk assessment methodology is reliant on available and precise precursory data	Used publicly available data to create a framework accident model and risk assessment algorithm based on DWH series of events
Eckle et al. 2012	17	8-91	Global data takes into account risk factors potentially not relevant to Gulf of Mexico	More data points on extreme spill events; 1213 accidents total. Data from 1974-2010. Bayesian model fitting.
Ji et al. 2014	165	41-500	Using all available data, which is mostly shallow water spill data, to analyze for ultra deepwater drilling risk	Uses multiple approaches and 49 years of spill data (rather than only one or a few data points). Data from 1964-2012. Maximum likelihood model fitting.

In summary, BOEM provided NMFS with information that two oil spills greater than or equal to 10,000 bbl may occur over the duration of the proposed action. Based on the historical

[2] Note also that, as shown in Table 4, Eckle et al 2012 estimated a 17 year recurrence frequency based on a larger number of large events with a confidence interval range from 8-91 years.

information on oil spills and advances in offshore drilling safety, we anticipate that one of these spills will be on the order of approximately 100,000 bbl (Ji et al. 2014). We define the largest spill size possible as a median spill volume of 1.1 million bbl (Mbbl) in the Gulf of Mexico (between 900,000-1.3 Mbbl). We determined this volume of oil by assessing how long a spill might last and how much oil could flow over that time. We also determined that a median volume would be a reasonable estimate of the largest spill size possible because of the safety measures that were implemented with the 2012 drilling rule and subsequent safety measures.

The volume of oil spilled during an uncontrolled blowout is highly dependent on the flow rate per day and the duration of the flow. BOEM estimates an uncontrolled flow rate of 30,000-60,000 bbl per day is possible if an uncontrolled blowout occurs. These flow rates are based on BOEM data from well tests, the maximum flow rate from the 1979 Ixtoc blowout in shallow water, and the maximum flow rate estimated for the 2010 DWH oil spill in deep water. Considering the time to deploy a capping stack and accounting for poor weather or other logistical delays that could arise, we conservatively consider the possibility of BOEM's position that an uncontrolled blowout release could last up to 30 days before containment, which we estimated could result in a release of up to 1.1 Mbbl of oil. BOEM and BSEE, predicted the return period for an extremely large event due to a well-control incident in the Gulf of Mexico (Ji et al. 2014) within the next 165 years with a 95 percent confidence interval between 41-500 years. NMFS will defer to the BOEM and BSEE analysis for this conclusion based on their expertise in this subject, and accordingly will not carry an extremely large event into our analysis of the effects of the action for the hypothetical occurrence of this low-probability extremely large (greater than 1 Mbbl) event.

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BSEE. 2016. Bureau of Safety and Environmental Enforcement 2016 Annual Report.

BSEE. 2017. Loss of well control occurrence and size estimators. USDOI Bureau of Safety and Environmental Enforcement.

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Ji, Z.-G., W. R. Johnson, and G. L. Wikel. 2014. Statistics of Extremes in Oil Spill Risk Analysis. Environmental Science & Technology 48(17):10505-10510.

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Ramseur, J. L. 2010. Deepwater Horizon Oil Spill: The Fate of the Oil. Congressional Research Service, Washington D.C.

Rathnayaka, S., F. Khan, and P. Amayotte. 2013. Accident modeling and risk assessment framework for safety critical decision-making: application to deepwater drilling operation. Proceedings of the Institution of Mechanical Engineers Part O: J Risk and Reliability 227(1):86-105.

Xue, L., J. Fan, M. Rausand, and L. Zhang. 2013. A safety barrier-based accident model for offshore drilling blowouts. Journal of Loss Prevention in the Process Industries 26(1):164-171.

Appendix H. Cetacean and Sea Turtle Wildlife Response Guidance for the Gulf of Mexico

I. Introduction

The protection of wildlife during the course of an oil release event is an essential element in every oil spill response operation. A Wildlife Response Plan (WRP) as part of an OSRP provides for coordinated, immediate, and effective protection, rescue or recovery, and rehabilitation of wildlife resources present in the oceanic, coastal, and inland waters of the Gulf of Mexico. WRPs typically focus on bird species and coastal terrestrial animals. This document provides a framework for Cetacean *and Sea Turtle Response Plans*, which should be included in the larger WRP covering all potential impacted wildlife based on the geographic area covered[1].

Under incident command, NOAA's National Marine Fisheries Service (NMFS) will lead marine mammal and sea turtle response efforts for spills that may impact any sea turtle species, cetaceans, and/or pinnipeds. Therefore, the Wildlife Response Plan for these species must ensure that NMFS is notified immediately if any sea turtle or cetacean species are suspected to be impacted, using the contact information provided in this document. If response is determined to be necessary, NMFS will lead the response and follow existing protocols found in approved agency Oil Spill Response Guidelines documents. The WRP and OSRP must ensure that NMFS is engaged and included in the response efforts, and that the responsible party is prepared to provide appropriate and reasonable resources for response efforts.

II. Marine Mammal and Sea Turtle Response Plans and Guidance Documents

Oil spill response planning and strategies should follow standard protocols, techniques, and best management practices for particular taxa, species and habitats, as available. NMFS developed Oil Spill Response Guideline documents for use during oil spills, and recommends that these Guidelines be incorporated by reference to WRPs, to avoid duplication and variability between

[1] Wildlife Response Plan considerations for birds are not included in this document, although that information is available in other documents and formats. Additionally, this document does not address response strategies to other ESA-listed species under NMFS jurisdiction, such as corals, smalltooth sawfish, and sturgeon. If an oil spill involves these species, please consult with NMFS representatives on response needs. Emergency consultation for responses which may affect ESA-listed species in the Gulf of Mexico can be accomplished by emailing nmfs.ser.emergency.consult@noaa.gov.

protocols. This will allow for consistent and coordinated response efforts regardless of the responsible party. NMFS recommends that all WRPs include the following information related to marine mammal and sea turtle species that are present in the specific geographic area covered: 1) the notification/contact information listed in Section III below, 2) reference to the following two documents, and 3) overview of response roles and anticipated response strategies including pre-planned facility and equipment availability during a spill. For response to marine mammals and sea turtles during a spill, response strategies will likely include initial reconnaissance efforts at a minimum. Based on initial reconnaissance, response strategies may also require continued reconnaissance/surveillance throughout the response, recovery of stranded and oiled animals, triage, and rehabilitation care. Further details on these activities including descriptions of procedures and safety considerations can be found in the following guidance documents.

Title: *Pinniped and Cetacean Oil Spill Response Guidelines*
Citation: Ziccard, M., Wilkin, S., Rowles, T.K. and S. Johnson. 2015. NOAA Technical Memorandum.
URL: https://www.fisheries.noaa.gov/resource/document/pinniped-and-cetacean-oil-spill-response-guidelines
These Guidelines provide a foundation for coordination and communication between local, state and federal oil spill response agencies and the marine mammal conservation, research and welfare communities (including marine mammal stranding networks and research scientists). More specifically, these Guidelines provide key information to, and standardize activities of, marine mammal responders to build and maintain oiled wildlife readiness at a national level.

Title: *Guidelines for Oil Spill Response and Natural Resource Damage Assessments: Sea Turtles*
(in review): Stacy, B.A., B.P. Wallace, T. Brosnan, S.M. Wissmann, B.A. Schroeder, A.M. Lauritsen, R.F. Hardy, J.L. Keene, S.A. Hargrove. 2018. Guidelines for Oil Spill Response and Natural Resource Damage Assessment: Sea Turtles. U.S. Department of Commerce, National Marine Fisheries Service and National Ocean Service, NOAA Technical Memorandum [Designated number], Washington, D.C.
URL: https://www.fisheries.noaa.gov/resource/document/guidelines-oil-spill-response-and-natural-resource-damage-assessment-sea-turtles
These guidelines provide a foundation for coordination and communication between local, state and federal oil spill response agencies for sea turtle response efforts. These guidelines specifically cover actions that may be undertaken during emergency response to oil spills or subsequent Natural Resource Damage Assessment (NRDA), and provide standardized protocols for responders. Since the circumstances of each oil spill vary significantly, the information in this document is not meant to be prescriptive, it is intended to supplement existing regulations, policy, and guidance.

III. Notification of Spills

NMFS Office of Protected Resources coordinates agency assessment of the need for response and leads response efforts for spills that may impact sea turtles, and cetaceans. If a spill may impact cetaceans, or sea turtles, NMFS Protected Resources Contacts should be notified and they will initiate notification of other relevant parties.

NMFS Protected Resources Contacts for the Gulf of Mexico:

- Marine mammals- Southeast emergency stranding hotline 1-877-433-8299
- Sea turtles- Dr. Brian Stacy at brian.stacy@noaa.gov and 352-283-3370$_{(cell);}$ or Stacy Hargrove at stacy.hargrove@noaa.gov and 305-781-7453$_{(cell)}$
- Other ESA-listed species- ESA section 7 consulting biologist: nmfs.ser.emergency.consult@noaa.gov

Appendix I. Explosive Removal of Structures Measures

I. *Sargassum* habitat monitoring

"*Sargassum* habitat" is defined as the presence of *Sargassum* in sufficient amounts that serve as developmental habitat in which small juvenile sea turtles are likely to be found. Small juvenile turtles are extremely difficult to detect and *Sargassum* habitat will be used as the primary indicator of their presence in an impact zone. Typically, the occasional presence of a few, small *Sargassum* "clumps" are not considered developmental habitat. *Sargassum* habitat for sea turtles is visually described as mats, continuous lines, broken windrows (short lines or non-linear clumps), or scattered patches (Table 135). NMFS PSOs will be required to monitor local conditions to determine if *Sargassum* habitat is present based on the hourly conditions at a decommissioning site and implement the appropriate measures.

Table I- 1. Description of Sea Turtle Sargassum Habitat Types {Witherington, 2012 #648}.

***Sargassum* Habitat Type**	**Description**
Mat	One or more consolidated areas of *Sargassum* forming a mat large enough to provide shelter and/or food for a small sea turtle.
Continuous Line	One or more contiguous meandering lines or scattered patches along a linear path. Lines may be narrow or wide. These lines are often associated with convergence zones.
Broken Windrows	Many parallel, short lines or clumps that may or may not be distributed linearly
Scattered patches	Numerous patches scattered over an area

II. Requirements for Establishing Impact Zones

A. Impact zones in both shallow and deep water are determined by the net explosive weights used during a decommissioning event. The impact distance(s) shall be based on the largest charge size proposed to be used during a removal event when multiple charges are used. The measures herein apply to any charge size up to 500 lb. The charge weight establishes the specific mitigation scenario that must be adhered to as a permit condition.

B. Impact zones for each scenario shall be calculated using the most recent version of the Underwater Calculator (UWC) that has been reviewed and approved by NMFS. The current required impact zones (Table 136) are based on UWC version 1.5.3 that is the latest approved version at the time of this opinion. Review and approval of UWC revisions will be completed according to the second tier consultation procedures detailed in section 4 of this opinion.

Table I- 2. Impact zones for net explosive weights based on underwater calculator version 1.5.3.

Net Explosive Weight (lb)	Impact Zone Distance	
	BLM	AML
1-10	261 m (856 ft)	293 m (961 ft)
>10-20	373 m (1,224 ft)	522 m (1,714 ft)
>20-80	631 m (2,069 ft)	829 m (2,721 ft)
>80-200	941 m (3,086 ft)	1,126 m (3,693 ft)
>200-500	1,500 m (4,916 ft)	1,528 m (5,012 ft)

C. NMFS understands all decisions on explosive composition, configuration, and usage need to be made by the qualified explosive contractors in accordance with the applicable explosive-related laws and regulations. BSEE or their permitee shall provide a written blasting plan to the PROP Program Manager prior to the anticipated blasting date. The blasting plan shall include the number of and type of structures, number of decommissioning events, type of explosives, and weight of explosives. Any changes to the net explosive weights detailed in the blasting plan shall be submitted in writing to the PROP program manager or lead PSO on site. The PROP Program Manager or lead PSO will determine the appropriate scenario measure (described below) and impact zone required based on the final net explosive weights used for the removal.

D. PSOs may use binoculars and the naked eye to monitor the exclusion zones. The sighting distance of all listed species and *Sargassum* habitat that result in delays must be recorded.

E. Buoys or some visible markers will be necessary for visual reference of the impact zone when only surface monitoring is required. The perimeter of impact zones should be demarcated (e.g., brightly colored buoys, vessels, or other markers) for visual reference.

F. If any ESA-listed species, or *Sargassum* habitat indicative of small juvenile sea turtles are present in the impact zone, a detonation must not proceed. Steps for tracking animals, inspecting *Sargassum* habitat, delay periods, and additional monitoring are detailed below.

III. Requirements for differing scenario mitigations

A. Permittees must fully comply with the relevant measures according to impact zones in Table 136 and the mitigation scenarios in Table 137. Table 136 provides the impact zone distances required based on the net explosive weight used. Table 137 summarizes the required mitigation and monitoring surveys, and duration of monitoring required. Sea turtles can remain submerged on a single dive for well over 30 minutes, hence the reason for increasing the pre-detonation aerial survey to 45 minutes (Byles, 1989; Renaud, 1995; Gitschlag, 1996).

Table I- 3. Mitigation overview for net explosive weights used in any configuration in shallow water (SW; less than 200 m) and deep water (DW; greater than 200 m).

Mitigation scenario Number	Net explosive weight (lb)	Pre-Det Surface Survey (min)	Pre-Det Aerial Survey (min)	Pre-Det PAM (min)	Animal Sightings Waiting Period (min)	*Sargassum* Habitat Waiting Period	Post-Det Surface Survey (min)	Post-Det Aerial Survey (min)	Post-Post-Det Aerial Survey within one Week
SHALLOW WATER									
SW-1	1-10	60	N/A	N/A	30	Until visually inspected or *Sargassum* floats out of Impact Zone	30	N/A	No
SW-2	>10-20	90	45	N/A	30		N/A	45	No
SW-3	>20-80	90	45	N/A	30		N/A	45	No
SW-4	>80-200	120	60	N/A	30		N/A	45	No
SW-5	>200-500	150	90	N/A	45		N/A	45	No
DEEPWATER									
DW-1	1-10	90	N/A	N/A	45	Until visually inspected or *Sargassum* floats out of Impact Zone	30	N/A	No
DW-2	>10-20	90	45	N/A	45		N/A	45	No
DW-3	>20-80	90	60	150	45		N/A	45	Yes
DW-4	>80-200	150	60	180	45		N/A	45	Yes
DW-5	>200-500	180	90	270	45		N/A	45	Yes

B. Permittees must stagger the detonation of multiple charges in a series by an interval of at least 0.9 sec (900 msec) between blasts. Otherwise, the combined charge sizes (or net explosive weight) will be used to determine the impact zone.

C. Detonations must only occur during daylight and during a time that would allow for post- detonation surveys. Monitoring will cease if the lead PSO determines that weather or marine conditions are not adequate for visual observations.

D. Scare charges shall not be used to clear impact zones of sea turtles or ESA-listed whales (i.e., sperm whale).

E. Images/pictures taken during any surveys are the property of the U.S. Government and should not be sold, duplicated or used in any way other than for which the project it was intended.

F. Unusual Circumstances: Occasionally, sea turtle(s) remain within the impact zone or are present in high numbers. On rare occasions, very small turtles may be seen in absence of *Sargassum* habitat near vessels from which monitoring is occurring. During these unusual circumstances, the on-site NMFS PSO shall exercise discretion in the implementation of measures or modification of the mitigation procedures that serve to avoid or minimize impacts to sea turtle(s). Typically, modifications of

mitigations include increasing the duration of monitoring periods, increasing the number of PSOs, delaying blasting, or a combination of measures. The lead PSO will coordinate with the PROP Manager, appropriate BSEE personnel, and NMFS ESA section 7 consulting biologist when circumstances necessitate additional monitoring.

IV. Requirements for Surface Monitoring Surveys

A. A surface monitoring survey is required for all blasting scenarios and must be conducted for the length of time indicated for the net explosive weights in Table 136 and Table 137.

B. Surface monitoring is generally conducted by at least two PSOs. Surface monitoring surveys are to be conducted from the highest vantage point(s) and/or other location(s) that provide the best, clear view of the entire impact zone. These vantage points may be on the structure being removed or proximal surface vessels such as crew boats and derrick barges. Additional PSOs will be positioned around the decommissioning site, as determined by the PROP manager/coordinator in consultation with the lead PSO for additional structures, large net explosive weights, or other circumstances as needed.

C. Surface monitoring must be conducted in adequate light during daylight hours (sunrise to sunset) and with an adequate line of sight including meteorological conditions free of rain or fog, and free of other visual obstructions such as other work vessels.

D. For mitigation scenarios requiring only surface monitoring and no aerial monitoring, surface monitoring must be conducted under good environmental conditions that are conducive for monitoring for sea turtles and marine mammals. Surface-only monitoring shall be delayed if: 1.) Sea conditions exceed Beaufort Wind Force Scale 4.5 (see Table 138), or 2.) inadequate line of sight including poor light conditions, meteorological conditions (e.g., rain or fog) and other visual obstructions such as other work vessels.

Table I- 4. Beaufort Sea State Scale.

Beaufort State	Wind mph	Wind Knots	Wave Height (ft)	Description
0 (calm)	0-1	0-1	0	Sea surface like a mirror
1 (light air)	1-3	1-3	0.33-0.65	Ripples with the appearance of scales, but no foam crests
2 (light breeze)	4-7	4-6	0.66-1.9	Small wavelets, more pronounced. Crests have glassy appearance, but do not break.
3 (gentle breeze)	8-12	7-10	2-3.2	Large wavelets. Crests begin to break. Foam of glassy appearance. Perhaps scattered white horses.

Beaufort State	Wind mph	Wind Knots	Wave Height (ft)	Description
4 (moderate breeze)	13-18	11-16	3.3-6.5	Small waves, becoming larger; fairly frequent white horses.
4.5 (moderate-fresh breeze)	≤15.5	≤13.5	≤4.9	Small waves, crests break, scattered but regular white horses
5 (fresh breeze)	19-24	17-21	6.6-9.8	Moderate waves, more pronounced long form, many white horses, some spray possible

E. For charge sizes between 0-10 lb, the detonation may proceed if ESA-listed species or *Sargassum* habitat is not sighted.

F. If a listed species is sighted, or sighted heading inbound toward the impact zone, a waiting period is required (see Waiting Periods in "F" below), or

G. If *Sargassum* habitat is sighted in the impact zone, , a waiting period is required until the *Sargassum* habitat drifts out of the impact zone (see Waiting Periods in "F" below). Alternatively, a vessel-based PSO could inspect the *Sargassum* for juvenile sea turtles. This must be done from a small vessel or inflatable boat so that an observer will be close to the water surface and can see small turtles. If no sea turtles are sighted, the waiting period ends and the survey can continue for the remaining period required under the mitigation. If a sea turtle(s) is sighted, the waiting period must continue until the *Sargassum* drifts out of the impact zone.

V. Requirements for Pre-Det Aerial Surveys

A. Aerial monitoring surveys are to be conducted from helicopters running standard low-altitude search patterns over the extent of the decommissioning area, including the impact zone that corresponds to the appropriate mitigation scenario.

B. Aerial surveys will be restricted to daylight hours only and cannot begin until the requisite surface monitoring survey has been completed.

C. Aerial surveys will cease if the lead PSO determines that weather or marine conditions are not adequate for visual observations, or when the pilot/removal supervisor determines that helicopter operations must be suspended.

D. When two or more PSOs are on site, NMFS may decide two PSOs conduct the aerial survey or have one or more PSOs continue surface monitoring while the other observer flies the survey. The helicopter will traverse the impact zone at low speed/altitude in the specified survey pattern.

E. Flight patterns during pre-detonation and post-detonation surveys shall follow the procedures listed in Table 139. At any time during the survey period, the flight path may be altered to investigate sightings and confirm their location in reference to the impact zone.

Table I- 5. Flight patterns during pre-detonation surveys. All surveys should begin at the center of the impact zone. At any time during the entire survey period it may be necessary to alter the flight path to investigate sightings and confirm their location in reference to the impact zone.

Flight Path	30-minute	45-minute	60-minute	90-minute
Follow a spiraling or corkscrewing flight path out from the center of the impact zone to the perimeter of the impact zone. This should be followed by a gradually contracting spiral flight path until the aircraft returns to the center of the impact zone. Repeat the pattern for the specified time period.	10 minutes	20 minutes	25 minutes	40 minutes
Unless higher priority targets (ex. turtles, dolphins, *Sargassum*) are present, the aircraft should survey outside of the impact zone to a distance approximately equal to the radius of the impact zone to determine if any protected species (sea turtles or marine mammals) might be moving into the area. Expanding and contracting spirals should again be used for the	5 minutes	5 minutes	5 minutes	5 minutes
The aircraft should survey inside the impact zone and follow the same procedures as during the first part of the survey. However, near the end of the survey period the flight path should usually be concentrated near the center of the impact zone since this is where animals will have the highest risk of [illegible]	15 minutes	20 minutes	30 minutes	45 minutes

F. For charge sizes greater than 10-500 lb, the detonation may proceed if listed species are not sighted.

G. If listed species are sighted, or sighted heading inbound toward the impact zone, a waiting period is required (see Waiting Periods below).

H. If *Sargassum* habitat is sighted, a waiting period is required until either a) a vessel-based PSO inspects the *Sargassum* from a small vessel or inflatable boat for juvenile sea turtles to determine if a *Sargassum* waiting period is required, or b) no vessel-based inspection occurs and a waiting period is triggered until the *Sargassum* has drifted out of the impact zone. If no sea turtles are sighted during a PSO inspection, the surface monitoring can continue for the remainder of the required monitoring period.

VI. Requirements for Passive Acoustic Monitoring (PAM)

A. BOEM and BSEE must require operators to provide for review a plan for the use of passive acoustic monitoring for marine mammal detection in the relevant deepwater mitigation scenarios (DW-3, DW-4, and DW-5). The plan must include on-site monitoring protocols, description of the passive acoustic system, software used, recording and storage of data, and other aspects of acoustic monitoring.

B. Persons conducting acoustic surveys will be required to comply with NMFS-approved passive acoustic monitoring protocols and use approved devices and technicians.

C. Acoustic surveys will be run concurrent with requisite pre-detonation surveys, beginning with the surface observations and concluding at the finish of the aerial surveys when the detonation(s) is allowed to proceed. Operators must also report on an assessment of the usefulness, effectiveness, and problems encountered with the use of the method. PAM operators shall notify NMFS PSOs immediately when any acoustic targets are detected.

D. For mitigation Scenarios DW-3, DW-4, and DW-5, the detonation may proceed if ESA-listed whales (i.e., sperm whale) are not detected with PAM and the other pre-det surveys do not detect listed species or Sargassum habitat. If ESA-listed whales are detected with PAM (or listed species or Sargassum habitat are otherwise sighted), a waiting period is required (see Waiting Periods below).

VII. Requirements for Waiting Periods for Surface, Aerial, and PAM Surveys

A. For pre-det surveys. If sea turtle, Sargassum habitat or ESA-listed whales (i.e., sperm whale) are observed within (or about to enter, heading inbound) the impact zone of any pre-detonation survey, detonations must be delayed until no protected species are inside the impact zone or the *Sargassum* has drifted out of the impact zone. The waiting period must be completed before the monitoring protocol for the requisite mitigation, and following measures can continue. The purpose of a waiting period is to allow any inbound animal(s) within the impact zone to exit the impact zone under their own volition. For small juvenile sea turtles, the purpose of the waiting period is to allow floating *Sargassum* habitat to drift out of the area or to confirm no turtles are present in the *Sargassum*.

B. For surface, aerial, PAM surveys. When listed species are inside the impact zone or inbound toward the impact zone during a surface, aerial or PAM survey:

i. Halt the detonation countdown and implement the waiting period,

ii. Continue opportunistic monitoring during the required waiting period after the last sighting.

iii. If additional sightings occur inside the impact zone or animals sighted heading inbound during the waiting period, then continue surface surveys and start a new waiting period after the occurrence of the last sighting.

iv. Except for waiting periods triggered by Sargassum habitat, anytime a waiting period for an aerial survey or for a surface survey for blast scenarios with surface only surveys (when no aerial survey is required) is triggered by a sea turtle or marine mammal sighting, the interrupted survey must be completed over in its entirety. For blast scenarios that include both survey types, only the aerial survey would need to be repeated.

v. Anytime a surface survey waiting period is due only for *Sargassum* habitat, a waiting period is required until either a) a vessel-based PSO inspects the *Sargassum* and determines no turtles are present, or b) no vessel-based inspection occurs and a waiting period is triggered until the *Sargassu*m has drifted out of the impact zone. If no sea turtles are sighted during a PSO inspection of Sargassum habitat, the surface monitoring can continue for the remainder of the required monitoring period.

vi. Anytime an aerial survey waiting period is triggered only due to Sargassum habitat (no marine mammals or large juvenile or adult sea turtles sighted), only the aerial survey needs to be repeated.

vii. Other than in the case of waiting periods described above, any interrupted surface or aerial surveys must be repeated in their entirety. Also, the post-detonation aerial survey must begin immediately following completion of the pre-detonation surface survey.

VIII. Requirements for Post-Detonation and Post-Post Detonation Monitoring Surveys

The primary purpose of post-det and post-post-det surveys is to detect any listed species that may have been impacted (stunned, injured or killed) by the detonation and monitor the effectiveness of the pre-det mitigation requirements. Post-det and post-post-det surveys must follow the following measures.

A. A 45-minute post-detonation aerial survey must be conducted by the PSO(s) for all explosive use greater than 10 lb. The aerial survey must be conducted immediately upon conclusion of the detonation.

B. For deepwater, mitigation scenarios DW-3, DW-4 and DW-5, post-post-detonation aerial monitoring surveys must be conducted within 2-7 days after detonation activities conclude, by either helicopter or fixed-wing aircraft. Any distressed, stunned, injured, or dead marine mammals will be noted in the survey report, and if possible, tracked and collected after notifying the National Marine Fisheries Service.

C. Detonations shall not occur if the post-detonation survey cannot be concluded prior to sunset.

D. For post-detonation surveys, follow a spiraling or corkscrewing flight path out from the center of the impact zone to the perimeter of the impact zone. This should be followed by gradually contracting spiral flight path until the aircraft returns to the center of the impact zone. If strong currents are present, the down current area should be surveyed outside the impact zone to an appropriate distance. Repeat the pattern for the specified time period.

E. For post-post-detonation surveys, survey a 7x7 nmi grid centered over the removal site. This grid includes eight, parallel transect lines each measuring 7 nmi long and spaced approximately 1 nmi apart. If strong currents are determined to be present, the the grid may be shifted in the down current direction to an appropriate distance. Any injured or dead sea turtle or marine mammal must be recorded in the survey report and reported to the appropriate stranding network. The stranding network may request that the carcass be tracked and collected if possible.

IX. Requirements for the Recovery of Sea Turtles

A. BOEM and BSEE shall allow an option for trained diver(s) to attempt capture of sea turtles known to be present around a structure slated for removal by explosive severance. NMFS SERO shall be notified prior to any capture attempts and the capture, handling, holding, and release of sea turtles shall be under the guidance and supervision of NMFS PSOs

B. Sea turtles that are observed to be stunned, injured, or killed during post-det surveys or follow-up aerial surveys must be recovered by PSOs when it is possible to do so. The company and offshore service contractors on site must make assets available, such as vessels, divers, so PSOs can capture or recover stunned, injured, or dead turtles and transport them to shore.

C. Impacted sea turtles that are recovered alive or dead must be immediately transported to shore in coordination with NMFS. Turtles must be transported to an authorized rehabilitation facility for veterinary treatment, or properly stored for necropsy to document the injuries and cause of death.

D. If a sperm whale is unintentionally exposed to a blast, the incident must immediately be reported to the Marine Mammal Stranding Network at 1-877-WHALE-HELP (1-877-942-5343).

X. PSO Requirements

A. NMFS PSOs are required to perform surface and aerial surveys. These PSOs are qualified NMFS employees or contractors delegated under the Platform Removal Observer Program (PROP) of NMFS' Galveston Laboratory. Explosive-severance contractors or operators enter into agreements with the NMFS Galveston Laboratory to provide PSO monitoring. Under the agreements, NMFS achieves full cost recovery for the goods and services provided. Generally, at least 2 or 3 NMFS PSOs are required to conduct surveys for the mitigation scenarios. When simultaneous surface, aerial, or PAM surveys are required, teams of PSOs may be required. The PROP Manager will determine the required number of teams and PSOs depending on the complexity of severance activities, structure configurations, adequacy of structures and vessels to conduct effective monitoring, and other environmental monitoring conditions.

B. PSOs must brief affected crew and severance contractors of the monitoring efforts and notify topsides personnel to report any sighted animals or Sargassum habitat to the lead PSO immediately;

C. PSOs must establish an active line of communication (such as 2-way radio) with company and blasting personnel;

D. PSOs must devote the entire, uninterrupted survey time to listed species monitoring.

E. For aerial surveys, a PSO should sit in one of the seats in the front of the cockpit. This is typically on the port side of the aircraft next to the pilot. Whenever possible, a second PSO should sit on the opposite side of the aircraft so that both sides of the aircraft are surveyed. If additional PSOs are available, seating should be adjacent to a window. Communications equipment should be provided which allows the pilot and PSOs to talk to each other and which provides clear communications.

XI. Requirements for Reporting

A. Any take of listed species should be reported to NMFS at takereport.nmfsser@noaa.gov and nmfs.psoreview@noaa.gov. If the taking involves a whale, the lead PSO shall also report it immediately to the Marine Mammal Stranding Network at 1-877-WHALE-HELP (1-877-942-5343).

B. Final monitoring reports (also referred to as the trip report) will be prepared for each removal. The monitoring report responsibilities will be assumed by NMFS's lead PSO and completed following completion of the severance activities.

C. In addition to basic operational data (e.g., area and block, water depth, company/platform information), the trip reports must contain all of the applicable information:

i. Target: Type/Composition (pile, caisson, concrete piling, nylon mooring, etc.) and Diameter and Thickness

ii. Charge: Type (bulk, configured-bulk, linear-shaped, etc.), Charge weight/material (RDX, C4, HMX, etc.), Configuration (internal/external, cut depth [below mud line], water depth [above mud line], etc.), Deployment method (diver, ROV, from surface, etc.)

iii. Monitoring: Survey Type: (pre-det and post-det; surface, aerial, etc.), Time(s) initiated/terminated, Marine Conditions

iv. Observed/Detected summary: Type/number (basic description or species identification, if possible, during all survey types- i.e., surface, aerial, and acoustic and both during pre- and post-detonation periods), Location/orientation – inside/outside impact zone, inbound/outbound, etc., Any "halted-detonation" details – i.e., waiting periods, re-surveys, etc., Any "Take-Event" details – actual MPS injury/mortality

D. BOEM shall provide an annual report to the NMFS consulting biologist describing the total annual structures removed, sea turtle and sperm whale sightings during pre-detonation surveys, sea turtle and sperm whale sightings during post- detonation surveys, visibility during the surveys, details of sea turtles (including loggerhead, green, Kemp's ridley, hawksbill and leatherback sea turtles) and ESA-listed whales (i.e., sperm whale) that were observed injured, killed or otherwise affected and the measures taken for each sea turtle and sperm whale. These annual reports should be combined with any MMPA reporting requirements, as appropriate.

E. The annual reports shall be sent electronically by email to nmfs.psoreview@noaa.gov with "Decommissioning Protected Species Annual Report" in the subject header.

References:

Byles, R.A., 1989. Satellite telemetry of Kemp's ridley sea turtle, Lepidochelys kempi, in the Gulf of Mexico. In, Proceedings of the Ninth Annual Workshop on Sea Turtle Conservation and Biology, compiled by S.A. Eckert, K. L. Eckert and T. H. Richardson, NOAA Tech. Memo. NMFS-SEFC-232, pp. 25-26.

Renaud, M. L., 1995. Movements and submergence patterns of Kemp's ridley turtles (Lepidochelys kempii). J. Herpetology, Vol. 29, pp. 370-374.

Gitschlag, G. R. 1996. Migration and diving behavior of Kemp's ridley (Garman) sea turtles along the U.S. southeastern Atlantic coast. J. Experimental Marine Biology and Ecology, Vol. 205, pp. 115-135.

Appendix J. Sea Turtle Handling and Resuscitation Guidelines

Any sea turtles taken incidentally during the course of fishing or scientific research activities must be handled with due care to prevent injury to live specimens, observed for activity, and returned to the water according to the following procedures:

I. Sea turtles that are actively moving or determined to be dead (as described in paragraph (B)(4) below) must be released over the stern of the boat. In addition, they must be released only when fishing or scientific collection gear is not in use, when the engine gears are in neutral position, and in areas where they are unlikely to be recaptured or injured by vessels.

II. Resuscitation must be attempted on sea turtles that are comatose or inactive by:

   i. Placing the turtle on its bottom shell (plastron) so that the turtle is right side up and elevating its hindquarters at least 6 inches (15.2 cm) for a period of 4 to 24 hours. The amount of elevation depends on the size of the turtle; greater elevations are needed for larger turtles. Periodically, rock the turtle gently left to right and right to left by holding the outer edge of the shell (carapace) and lifting one side about 3 inches (7.6 cm) then alternate to the other side. Gently touch the eye and pinch the tail (reflex test) periodically to see if there is a response.
   ii. Sea turtles being resuscitated must be shaded and kept damp or moist but under no circumstance be placed into a container holding water. A water-soaked towel placed over the head, carapace, and flippers is the most effective method in keeping a turtle moist.
   iii. Sea turtles that revive and become active must be released over the stern of the boat only when fishing or scientific collection gear is not in use, when the engine gears are in neutral position, and in areas where they are unlikely to be recaptured or injured by vessels. Sea turtles that fail to respond to the reflex test or fail to move within 4 hours (up to 24, if possible) must be returned to the water in the same manner as that for actively moving turtles.
   iv. A turtle is determined to be dead if the muscles are stiff (rigor mortis) and/or the flesh has begun to rot; otherwise, the turtle is determined to be comatose or inactive and resuscitation attempts are necessary.

Any sea turtle so taken must not be consumed, sold, landed, offloaded, transshipped, or kept below deck.

These requirements are excerpted from 50 CFR 223.206(d)(1). Failure to follow these procedures is therefore a punishable offense under the Endangered Species Act.